January 30, 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 50-334/02-07, 50-412/02-07

Dear Mr. Bezilla:

On December 28, 2002, the NRC completed an inspection at Beaver Valley Unit 1 and Unit 2. The enclosed report documents the inspection findings which were discussed with you and members of your staff during an exit meeting on January 10, 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 two issues of very low safety significance (Green). One of these issues was determined to involve a violation of NRC requirements. However, because of the low safety significance and because the issue was entered into your corrective action program, the NRC is treating the issue as a Non-Cited violation in accordance with Section VI-A of the NRC's Enforcement Policy. If you deny the Non-Cited violation, 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 1; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington DC 20555-0001; and the NRC Resident Inspector at the Beaver Valley facility.

Since the terrorist attacks on September 11, 2001, the NRC has issued two Orders (dated February 25, 2002 and January 7, 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 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 25th 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 (PARS) 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 610 337-5146 if you have any questions regarding this letter.

Sincerely,

/RA/

John F. Rogge, Chief
Projects Branch No. 7
Division of Reactor Projects

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

Enclosures: Inspection Report 50-334/02-07; 50-412/02-07
Attachment: Supplemental Information

cc w/encl:
J. Lash, Plant General Manager
F. von Ahn, Director, Plant Engineering
L. Cosgrove, Director, Work Management
R. Donnellon, Director, Maintenance
M. Pearson, Director, Director Services and Projects
L. Freeland, Manager, Nuclear Regulatory Affairs & Corrective Actions
M. Clancy, Mayor, Shippingport, PA
R. Janati, Chief, Division of Nuclear Safety
C. Hynes - Director, Operations Training
Commonwealth of Pennsylvania
State of Ohio
State of West Virginia

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Region I Docket Room (with concurrences)
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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.	50-334/02-07, 50-412/02-07
Licensee:	FirstEnergy Nuclear Operating Company (FENOC)
Facility:	Beaver Valley Power Station, Units 1 and 2
Location:	Post Office Box 4 Shippingport, PA 15077
Dates:	September 29, 2002 - December 28, 2002
Inspectors:	D. Kern, Senior Resident Inspector G. Smith, Resident Inspector R. Barkley, Senior Project Engineer J. McFadden, Health Physicist P. Frechette, Security Specialist G. Hunegs, Senior Resident Inspector, Nine Mile Point P. Bissett, Senior Operations Engineer J. Herrera, Project Engineer
Approved by:	J. Rogge, Chief, Projects Branch 7 Division of Reactor Projects

SUMMARY OF FINDINGS

IR 05000334-02-07, IR 05000412-02-07; FirstEnergy Nuclear Operating Company; on September 29 - December 28, 2002; Beaver Valley Power Station, Units 1 & 2. Problem Identification and Resolution, and Event Follow-up.

The inspection was conducted by resident inspectors, a regional health physics inspector, regional security specialist, and regional projects inspectors. The inspection identified two Green findings, one of which was a Non-Cited violation. 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 may be "green" or be assigned a severity level after 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," Revision 3, dated July 2000.

A. Inspector Identified Findings

Cornerstone: Initiating Events

- **Green.** Station personnel failed to fully identify and resolve degradation of the Unit 1 turbine motoring condition alarm differential pressure instrument in 1999 and again in 2002. Ineffective problem identification and resolution, and a resulting lack of preventive maintenance led to an unplanned Unit 1 reactor trip.

  This finding was of very low significance because the issue did not effect the availability of mitigation equipment. The issue was not a violation because the differential pressure instrument is not subject to the requirements of 10 CFR 50, Appendix B (Section 4OA3.1).

Cross-cutting Issues: Problem Identification and Resolution

- **Green**. The inspectors determined that corrective actions for having no senior reactor operator (SRO) present in the Unit 2 control room during Mode 1 (at power) operation were untimely and incomplete. Senior reactor operator presence is required to oversee operation of safety related structures, systems, and components, and to act as Emergency Director during emergency events. Station management initially incorrectly concluded that the November 21, 2002, occurrence was isolated and did not implement measures to verify all licensed operators understood the regulatory requirements of 10 CFR 50.54(m)(2)(iii) for control room staffing. Nuclear Regulatory Commission inspectors independently determined that additional licensed operators were also unaware of the regulatory requirements for control room staffing and corrective action program requirements to address such an issue.

  This finding was not suitable for NRC Significance Determination Process evaluation, but has been reviewed by NRC management and is determined to be a Green finding of very low significance. Absence of SRO oversight during licensed control room activities increases the likelihood of human performance errors, which in turn increase the likelihood of and initiating event and reduce the availability of mitigating systems. Knowledge of SRO control room staffing requirements is important to ensure appropriate oversight of licensed control room activities. No further control room staffing deficiencies occurred during the 3-day period of untimely and incomplete corrective actions. This finding was a violation of 10 CFR 50, Appendix B, Criterion XVI "Corrective Action" (Section 4OA2.2).

B. Licensee Identified Violations

Violations of very low significance which were identified by the licensee have been reviewed by the inspectors. Corrective actions taken or planned by the licensee appear reasonable. The violations are listed in Section 4OA7 of this report.

Report Details

SUMMARY OF PLANT STATUS

Unit 1 began this inspection period at 100 percent power. On November 11, 2002, while performing a downpower for a scheduled maintenance outage, the reactor was manually tripped from 53 percent reactor power due to a turbine motoring condition alarm. The alarm was caused by a failed differential pressure switch instrument (Section 4OA3.1). Following completion of the maintenance outage, operators commenced a reactor startup and power escalation on November 12, 2002. Prior to reaching full power on November 24, the unit experienced a partial load rejection from 98 to 88 percent reactor power due to inadvertent closure of the No. 1 main turbine governor valve (Section 1R14.1). Subsequent troubleshooting efforts identified a sheared shaft on the No. 1 main turbine governor valve linear variable differential transformer (LVDT) guide shaft. Repairs were made to the LVDT and the unit was returned to 100 percent power on November 26. The unit continued to operate at full power for the rest of the inspection period.

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 operating surveillance tests (OST)

- 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 preventive maintenance procedures were reviewed to verify that the calibrations were performed correctly. The inspectors performed a walkdown of the 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 the heat trace alarm response procedures and interviewed control room operators to assess their understanding of cold weather protection for equipment and associated alarms.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignments

a. Inspection Scope

The inspectors performed a complete system walkdown of the Unit 1 river water system and a partial system walkdown of the Unit 2 reactor protection system.

The inspectors reviewed Operating Manual (OM) Figure Numbers 30-1 through 30-6 and procedure 1OM-30.3.B.1, “River Water Valve List,” Rev. 30, to determine proper equipment alignments. In addition, the inspectors reviewed and evaluated impact on river water system operation for the open work orders (WOs), design change packages (DCPs), engineering evaluations, and corrective action program condition reports (CRs). The system health report was reviewed, and open issues were discussed with the system engineer.

The inspectors reviewed OM Figure Number 1-1, and Procedure 1OM-1.2.B, “Set points," Rev. 9, to determine proper equipment alignments and set points. In addition, the inspectors reviewed and evaluated impact on the reactor protection system operation for open WOs, DCPs, engineering evaluations, and corrective action program condition reports. The system health report was reviewed and open issues were discussed with the system engineer.

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 1 Cable Spreading Room (Fire Area CS-1)
- Unit 1 Component Cooling Water Pumps Area (Fire Area PA-1E)
- Unit 1 Containment Building (Fire Area RC-1)
- Unit 2 Cable Tunnel (Fire Area CT-1)
- Unit 2 Normal Switchgear Room (Fire Area SB-4)
- Unit 2 Cable Vault and Rod Control Area Cable Tunnel (Fire Area CV-3)
- Unit 2 Cable Vault and Rod Control Area (Fire Area CV-4)
- Unit 2 Orange/Purple Motor Control Center Room (Fire Area PA-6/7)
- Unit 2 Auxiliary Building General Area (Fire Area PA-3)

The inspectors reviewed the fire protection conditions of the above listed areas in accordance with the criteria delineated in Nuclear Power Administrative Manual, ½-ADM-1900, “Fire Protection,” Rev. 1. 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.

.2 Fire Brigade Drill

a. Inspection Scope

The inspectors observed a Unit 1 fire drill in the machine shop located within the radiologically controlled area of the service building. The drill scenario was a fire which consumed flammable materials left in two 55-gallon barrels which had been staged following the recent maintenance outage. Hazards included the spread of potentially contaminated materials and runoff water from the firefighting activity to the Ohio River. The inspectors reviewed: 1) the effectiveness of communications; 2) the assessment of the fire and the use of proper fire fighting strategy; 3) the adequacy and condition of fire fighting equipment; 4) treatment of fire victims; and 5) the knowledge and skill of the fire brigade. Although no fire fighting strategy existed for this area, this as well as other deficiencies were documented in a CR. The drill critique was also observed and the drill assessment was accurately documented as required on Figure 48.5.A-3, “Emergency Squad and Fire Brigade Drill Report,” Rev. 0.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification

.1 Quarterly Licensed Operator Requalification Simulator Scenarios

a. Inspection Scope

The inspectors observed a Unit 1 and two Unit 2 licensed operator requalification training sessions 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 scenarios listed below:

- 2002 Annual Requalification Exam Unit 1 Drill 30, Rev. 2A
- 2002 Annual Requalification Exam Unit 2 Drill 27, Rev. 0B
- 2002 Annual Requalification Exam Unit 2 Drill 30, Rev. 0A

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. The inspectors verified operator response during the training scenarios was consistent with associated station procedures listed below:

- 1OM-53A.1.E-0, “Reactor Trip or Safety Injection,” Rev. 2
- 1OM-53A.1.E-2, “Faulted Steam Generator Isolation,” Rev. 0
- 1OM-53C.4.1.6.7, “Excessive Primary Plant Leakage,” Rev. 0
- 2OM-53A.1.E-0, “Reactor Trip or Safety Injection,” Rev. 3
- 2OM-53A.1.E-2, “Faulted Steam Generator Isolation,” Rev. 2
- 2OM-53A.1.E-3, “Steam Generator Tube Rupture,” Rev. 3
- 2OM-53C.4.2.6.4, “Steam Generator Tube Leakage,” Rev. 13
- Emergency Preparedness Procedure (EPP) /1-1a, “Beaver Valley Power Station Unit 1
- Emergency Action Levels,” Rev. 6
- EPP /1-1b, “Beaver Valley Power Station Unit 2 Emergency Action Levels,” Rev. 6

b. Findings

No findings of significance were identified

.2 Biennial Licensed Operator Requalification Review

a. Inspection Scope

The following inspection activities were performed using NUREG-1021, Rev. 8, Supplement 1, “Operator Licensing Examination Standards for Power Reactors,” Inspection Procedure Attachment 71111.11, “Licensed Operator Requalification Program,” and NRC Manual Chapter 0609, Appendix I, “Operator Requalification Human Performance Significance Determination Process,” as acceptance criteria.

The inspectors reviewed documentation of operating history since the last requalification program inspection. Documents reviewed included NRC inspection reports, licensee event reports (LERs), and licensee deficiency reports. The inspectors also discussed facility operating events with the resident staff. The inspectors did not detect operational events that were indicative of possible training deficiencies.

The operating tests for the week of October 28, 2002, were reviewed for quality as well as how much test item overlap existed between exam weeks.

The inspectors observed the dynamic simulator exams and job performance measures (JPMs) being administered. These observations included facility evaluations of crew and individual performance on the dynamic simulator exam.

The inspectors observed simulator performance during the conduct of the examinations and reviewed performance testing and discrepancy reports to verify compliance with the requirements of 10 Code of Federal Regulations (CFR) 55.46 regarding simulator fidelity. A total of 44 simulator fidelity tests were reviewed, including the most recent steady state test and transient tests for plant startup, and reactor trip.

A sample of records for requalification training attendance, remediation and medical examinations were reviewed for compliance with license conditions and NRC regulations.

Instructors, and training/operations management, as well as a sample of individual licensed operators, were interviewed for feedback regarding the implementation of the licensed operator requalification program.

On December 30, 2002, the inspectors conducted an in-office review of licensee requalification exam results for the complete 2002 annual testing cycle. The inspection assessed whether pass rates were consistent with the guidance of NRC Manual Chapter 0609, Appendix I, “Operator Requalification Human Performance Significance Determination Process” (the comprehensive written exam was not administered this exam cycle for Unit 2). The inspectors verified for Beaver Valley Unit 1 that:

- Crew pass rate on the simulator test was greater than 80 percent. (Pass rate was 100 percent.)

- Individual pass rate on the simulator test was greater than or equal to 80 percent. (Pass rate was 96.9 percent)

- Individual pass rate on the walk-through job performance measures (JPMs) was greater than or equal to 80 percent. (Pass rate was 96.9 percent.)

- Individual pass rate on the written exam was greater than or equal to 80 percent. (Pass rate was 90.6 percent.)

- Individual pass rate for all portions of the exam was greater than or equal to 75 percent. (87.5 percent of the individuals passed all portions of the exam.)

The inspectors verified for Beaver Valley Unit 2 that:

- Crew pass rate on the simulator test was greater than 80 percent. (Pass rate was 90.0 percent.)

- Individual pass rate on the simulator test was greater than or equal to 80 percent. (Pass rate was 85.0 percent)

- Individual pass rate on the walk-through (JPMs) was greater than or equal to 80 percent. (Pass rate was 100.0 percent.)

b. Findings

No findings of significance were identified.

1R12 Maintenance Rule Implementation

a. Inspection Scope

The inspectors reviewed performance-based problems involving selected in-scope structures, systems, and components (SSCs) to assess the effectiveness of the maintenance program. Reviews focused on: (1) proper maintenance rule scoping, in accordance with 10 50.65; (2) characterization of failed SSCs; (3) safety significance classifications; (4) 10 CFR 50.65 (a)(1) and (a)(2) classifications; and, (5) the appropriateness of performance criteria for SSCs classified as (a)(2), and goals and corrective actions for SSCs classified as (a)(1). The inspectors reviewed FENOC's system scoping documents and system health reports and spoke with the responsible system engineers. The following systems were selected for review because of their risk significance:

- Unit 1 auxiliary feedwater system
- Unit 1 turbine and main condenser system
- Unit 1 supplemental leak collection and release system (SLCRS)

Additionally, the inspectors performed a partial walkdown of the systems, discussed the system status and recent performance with engineering and operations personnel, and reviewed the following corrective action program documents:

- CR 01-1866, "Motor Driven Auxiliary Feed Pump (FW-P-3B) Elevated Inboard Motor Bearing Temperature"
- CR 02-00585, "Steam Leakage on Auxiliary Feed Pump Turbine 1FW-P-2"
- CR 02-10899, "Governor Valve, GV-1MS-POS Broken LVDT (Linear Variable Differential Transformer) Rod"

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 ½-ADM-1800, "Shutdown Safety," Rev. 0; ½-ADM-2033, "Risk Management Program," Rev. 1; Nuclear Power Division Administrative Procedure (NPDAP) 7.12, "Non-outage Planning, Scheduling, and Risk Assessment," Rev. 11; NPDAP 8.30, "Maintenance Rule Program," Rev. 6; and Conduct of Operations Procedure 1/2OM-48.1.I, "Technical Specification Compliance," Rev. 9. The inspectors reviewed the routine planned maintenance, restoration actions, and/or emergent work for the following equipment removed from service:

- On October 19, 2002, technicians implemented technical evaluation report (TER) 12453, "Replacement Evaluation for Switchyard Bus No. 1 Breaker Failure Protection," which completed a major offsite power distribution switchyard protection scheme upgrade. One of the two offsite power supplies as well as system station service transformer (SSST)-2B, the backup power supply to the 'DF' emergency 4 kilovolt bus, were unavailable for the duration of the work. A periodic fire protection deluge system test was performed at the same time to minimize overall SSST-2B unavailability. These were elevated risk work activities (ORANGE risk level) which required several additional risk management measures. The inspectors observed pre-evolution risk assessment meetings, chaired by the plant manager, and pre-evolution job walkdowns to verify the activity was well understood and compensatory measures, where appropriate, were addressed. The work activity was completed in about 14 hours in accordance with WO 99-212160 and TER 12453.

- On October 29, 2002, the inspectors questioned the availability of the Unit 2 startup feedwater pump (2FWS-P24), due to the existence of a caution tag which stated the pump was awaiting surveillance testing after clearance pickup. Maintenance personnel had completed overhauling 2FWS-P24 on October 2, 2002, but post-maintenance testing (PMT) did not include associated solid state protection system relay testing. Operators considered the pump inoperable due to the expired surveillance. The associated surveillance test was successfully performed on November 26. The three auxiliary feedwater pumps remained operable during this period. Deficiencies associated with scheduling of surveillance testing and test failure were documented in CRs 02-9660 and 02-10519.

- On November 24, Unit 1 operators responded to an inadvertent closure of the No. 1 main turbine governor valve. Subsequent investigation revealed that the LVDT guide shaft had sheared. Maintenance personnel properly documented the condition and made repairs. Proper briefings and meetings ensured station risk was minimized.

- On November 25, 2002, mechanics replaced a relief valve (RV-1GN-119) on the supply line to the nitrogen backup accumulator for pressurizer power operated relief valve (PORV) PCV-RC-455D. Relief valve leakage had recently increased, requiring accumulator repressurization several times per day to retain PORV operability. The clearance boundary for the valve replacement required the PORV to be isolated and inoperable.

- On December 11, operators performed 1OST-30.01B, “[1WR-P-9B] Auxiliary River Water Pump Test,” Rev. 26. The inspectors noted that the daily on-line risk assessment did not incorporate river water pump unavailability, which existed when this test was performed in the past, due to the system test configuration. The inspectors evaluated recent procedure revisions and use of 1/2OM-48.1.I, “Technical Specification Compliance,” Rev. 12, which enabled operators to credit manual operator action for continued river water pump availability during this test.

- On December 15, operators secured and declared 1VS-F-4B, the ‘B’ train SLCRS fan, inoperable due to high vibration on the inboard bearing. Upon fan disassembly, the bearing was replaced. Following reassembly, the measurement between the fan and the inlet guard did not conform to the manufacturer’s recommendation. The bearings were then loosened and moved to accommodate shaft movement. During this process both the inboard and outboard bearings were damaged. Following bearing replacement and fan reassembly, post-maintenance testing revealed rubbing within the fan housing. The shaft was restored to the as-found condition without bearing disassembly. Post-maintenance testing was then performed satisfactorily. Job deficiencies were noted in CR 02-11545.

- On December 17, technicians calibrated pressure switch PS-1RW-104 using WO 01-8775. Plant conditions established for the calibration rendered one of two raw water pumps (WR-P-6B) inoperable. Therefore, cooling of the main turbine and main generator relied solely upon the remaining running raw water pump (WR-P-6A). Failure of the running pump and inability to restore WR-P-6B promptly (within a few minutes) during the calibration would require operators to trip the reactor and turbine. The inspectors walked down the equipment clearance, reviewed work instructions, and discussed contingency plans and train protection with shift personnel.

- On December 25, Unit 1 operators received annunciator A4-97, “Rod Control Non-Urgent Failure.” Technicians verified that one of two power supplies had failed. Station personnel evaluated the reliability of the remaining power supply, station power supply history, and industry experience to determine when and under what controls corrective maintenance would be performed to replace the failed power supply.

b. Findings

No findings of significance were identified.

1R14 Personnel Performance During Non-routine Plant Evolutions

.1 Unit 1 Partial Load Reject

a. Inspection Scope

The inspectors reviewed human performance during the following nonroutine plant evolution, to determine whether personnel performance caused unnecessary plant risk or challenges to reactor safety. The inspectors evaluated whether the evolution was properly implemented according to the applicable procedures.

- On November 24, 2002, Unit 1 experienced a partial load reject of approximately 200 megawatts-electric, and a corresponding reactor power reduction from 98 to 85 percent. The cause was the mechanical failure of an LVDT and electrical failure of a partial arc card in the analog electro-hydraulic control system which caused the number one governor valve (GV-1) to fail shut. Operators responded in accordance with 1OM-53C.4.1.35.2, “Load Rejection,” Rev. 9. Troubleshooting and repairs were performed in accordance with Nuclear Power Department Administrative Procedure 8.34, “Control of Troubleshooting Activities,” Rev. 3 and ½-ADM-0805, “Production/Generation Risk Determination,” Rev. 1. The event was documented in CR 02-10792.

b. Findings

No findings of significance were identified.

.2 (Closed) Licensee Event Report 50-412/02-02: Tagout Reduces Ability of Emergency Diesel Generator to Respond to Loss of Offsite Power

On February 18, 2002, Unit 2 operators identified that both emergency diesel generators (EDGs) were inoperable while the unit was in Mode 6 (refueling). Human performance deficiencies and process weaknesses were the primary causes of this event as discussed in NRC Inspection Report Nos. 50-334(412)/02-02. The event was previously documented as a Green finding in the inspection report, including event description and safety analysis. Enforcement determination was postponed, pending issuance and review of this LER. The inspectors determined that the event involved a violation of Technical Specification (TS) 3.8.1.2, for not maintaining at least one EDG operable during Mode 6 (refueling) activities. This licensee identified violation is documented in section 4OA7 of this report. No new issues were revealed by the LER. This LER was closed during an onsite review.

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 implications were properly addressed.

- During the service water latent issues review performed by FENOC in August 2002, the current design basis calculation 10080-N-779, “Main Intake Bay Silt Buildup Limits,” Rev. 0, did not demonstrate that Unit 1 river water system, Unit 2 service water system, and the Unit 1 & 2 ultimate heat sink functions are available during the licensing basis low river water level conditions. After an examination of the historical data on silt accumulation in the Ohio River, engineers determined that the ultimate heat sink function operability would not be challenged unless the river water level remained above the 666 ft. elevation for a period of 70 shifts. This issue was documented in CR 02-06899. The inspectors verified the operability assessment and corrective actions taken.

- During the month of October 2002, relief valve leakage (see Section 1R13) from the nitrogen backup accumulator for pressurizer PORV PCV-RC-455D caused the associated low pressure alarm to annunciate several times. The annunciator setpoint is 600 pounds per square inch gauge (psig). After frequently re-pressurizing the accumulator, due to increasing leakage, engineers determined that in the current operating mode (Mode 1), the PORV would remain operable as long as accumulator pressure was maintained above 200 psig. The inspectors verified the operability assessment. The accumulator leakage was corrected on October 25.

- On October 16, a through-wall leak was noted by the field operator on the river water system discharge piping from the ‘C’ component cooling water heat exchanger. The leak was at the weld between the 18-inch diameter discharge pipe and the 30-inch diameter common outlet drum. Basis for Continued Operation 1-02-003 was written to evaluate the degraded condition of the Class III river water piping. This section of piping is typically at a vacuum due to elevation differences between the leak area and the suction of the cooling tower pumps while design pressure is 85 psig. American Society of Mechanical Engineers (ASME) Code Case N-513 was invoked and appropriate compensatory measures were implemented. The system remained operable until the weld repairs were completed and the piping was restored to original configuration on October 23.

- On November 12, while preparing to establish cold shutdown plant conditions, the Unit1 residual heat removal pump common suction valve (MOV-1RH-700) failed to open electrically. Engineers determined the cause was pressure locking. Seven hours later, operators successfully opened the valve. Basis for continued operation (BCO) 1-02-004 was written to evaluate the degraded condition. The valve continued to fulfill its safety function as an isolation valve between high pressure and low pressure systems in Modes 1 to 4. Station personnel determined that the valve remained operable, capable of performing its safety functions and established compensatory measures consistent with the Updated Final Safety Analysis Report (UFSAR). Actions were identified to correct the degraded condition during the next Unit 1 refueling outage.

- On November 28, the reactor operator noted that open indication had been lost on the ‘A’ letdown orifice isolation valve, TV-1CH-200A. The valve was closed and proper closed indication (i.e., a green light), was received along with an expected decrease in letdown flow. Basis for Continued Operation 1-02-006 was generated to evaluate operability of this valve without the normal open indicating light. The safety function of TV-1CH-200A is to provide containment isolation by fully closing upon receipt of a containment isolation Phase ‘A’ signal. The BCO determined that this safety function could be verified by measuring voltage across relay V200AX. An energized V200AX coupled with the green closed indication would provide assurance that the valve, TV-1CH-200A, was indeed closed. The BCO also prescribed compensatory measures to verify operability during emergency events.

- The inspectors performed a cumulative review of various Unit 1 high risk open WOs for underlying operability issues. The focus included issues pertaining to degraded or nonconforming characteristics.

b. <u>Findings</u>

No findings of significance were identified.

1R16 <u>Operator Work-Arounds</u>

a. <u>Inspection Scope</u>

The inspectors reviewed the cumulative effects of the Unit 1 and 2 operator work-arounds as listed on the Managers Communications and Teamwork Meeting report dated October 9, 2002. The workarounds were reviewed to identify any effect on emergency operating procedure (EOP) operator actions, and impact on possible initiating events and mitigating systems. Included in this review were the effect on: (1) the reliability, availability, and potential for misoperation of a system; (2) the potential increase in initiating event frequency that could affect multiple mitigating systems; and, (3) the ability of operators to respond in a correct and timely manner to plant transients and accidents. The inspectors evaluated whether station personnel were identifying, assessing, and reviewing operator work-arounds as specified in ½ OM-48.3.M, "Conduct of Operations Equipment Administrative Controls - Operator Work-Arounds," Rev. 2. In addition, the inspectors reviewed the below operator work around to evaluate its impact on the reactor operator during emergencies.

- Operator work around 1-02-1-9, "TV-1CH-200A, Loss of Position Indication"

b. <u>Findings</u>

No findings of significance were identified.

1R19 <u>Post-Maintenance Testing</u>

a. <u>Inspection Scope</u>

The inspectors reviewed and/or observed several 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 evaluated:

- 2OST-30.6B, "Service Water Pump 2SWS*P21C Test on Train 'B' Header," Rev. 8, following preventive maintenance performed on service water pump discharge valve 2SWS-MOV102B using WOs 02-7253 and 02-7254

- 1OST-1.10, "Cold Shutdown Valve Exercise Test," Rev. 22, following repairs to the 'A', 'B', and 'C' atmospheric steam dump valves performed using WOs 00-25697, 02-00007, and 02-00008

- 1OST-10.4, "Residual Heat Removal System Valve Exercise," Rev. 11, and 1OST-10.5, "Leak Test [MOV-1RH-700 and 701]", Rev. 8, following repair of the MOV-1RH-700 motor operated actuator using WO 02-21359-002

- 1OST-16.2, "Supplementary Leak Collection and Release Test for Exhaust Through the Main Filter Bank - Train B," Rev. 7, following corrective maintenance to 1VS-F-4B performed using WOs 02-22833-001, 02-24330, 02-24057, 02-24373 and 02-24374

- Partial 2OST-1.11A, "Safeguards Protection System Train 'A' Blockable Test," Rev. 9, following corrective maintenance for the 2FWS-P24 output breaker performed using WO 02-24378

b. Findings

No findings of significance were identified.

1R20 Refueling and Outage Activities

a. Inspection Scope

Unit 1 was shutdown on November 12 for a brief planned maintenance outage. The inspectors observed selected operations, maintenance, and test 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, and1/2-ADM-1800, “Shutdown Safety,” Rev. 1. Specific performance attributes evaluated included configuration management, communications, instrumentation accuracy, and identification and resolution of problems. The inspectors monitored visual inspections of the reactor vessel head penetration area and reactor vessel bottom head area, looking for indications of cracking, corrosion, or boric acid leakage. The reactor vessel head inspection is further documented in Section 4OA5. Specific activities evaluated included:

- Inspection of the reactor vessel head
- Boric acid walkdown inspections in containment - cleanup and/or disposition of identified leaks
- Inspection of the reactor vessel bottom head
- 1OM-50.4.L, “Plant Heatup From Node 5 to Mode 3,” Rev. 5
- 1OM-50.4.D, “Reactor Startup From Mode 3 to Mode 2,” Rev. 39
- 1OM-52.4.A, “Raising Power From 5% to Full Load Operation,” Rev. 41

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing

a. Inspection Scope

The inspectors observed and reviewed the following OM procedures, OSTs, and maintenance surveillance procedures (MSPs), concentrating on verification of the adequacy of the test to demonstrate the operability of the required system or component safety function.

- 2OST-33.10A, “Deluge Valve Test,” Rev. 10, performed on emergency 4 kilovolt bus transformer SSST-1B

- 1OST-36.1, “Diesel Generator No. 1 Monthly Test,” Rev. 34 and 1OM-36.4.AJ, “No. 1 Diesel Generator 24-Hour Run,” Rev. 0. This was the first time either Unit 1 EDG was run for a 24 hour duration in over 15 years.

- 2OM-36.4.AI, “Emergency Diesel Generator [2EGS*EG2-1] 24 Hour Run,” Rev. 0. This was the first time either Unit 2 EDG was run for a 24-hour duration in over 15 years.

- 2MSP-1.05-I, “Solid State Protection System Train ‘B’ Bi-Monthly Test,” Rev. 16

- 1OST-13.1, “Quench Spray Pump [1QS-P-1A] Test,” Rev. 22

- The Inspectors reviewed the Unit 1 diesel fuel oil sampling and testing procedures. The results were examined against the criteria specified in the Unit 1 TS 4.8.1.1.2 d&e. The procedures examined are listed in the List of Documents Reviewed attachment.

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications

a. Inspection Scope

The inspectors reviewed temporary modifications (TMs) and associated implementing documents to verify the plant design basis and the system or component operability were maintained. Nuclear Power Division Administrative Procedure 7.4, “Temporary Modifications,” Rev. 8, specified requirements for development and installation of TMs. The inspectors reviewed all Unit 1 TMs for their cumulative impact on safety. In addition, the inspectors reviewed the following TMs in detail:

- TM 2-02-18, “Removal of Internals of Check Valve 2FPW-163L”

- TM 1-02-16, “Leak Repair of 1MS-81, 1B Steam Generator Residual Heat Release Check Valve”

b. Findings

No findings of significance were identified.

Emergency Preparedness (EP)

1EP6 Drill Evaluation

Unit 2 Control Room Simulator Emergency Plan Training Scenario

a. Inspection Scope

The inspectors observed an operations department training evolution conducted at the Unit 2 control room simulator to evaluate emergency procedure implementation, event classification, event notification, and protective action recommendation development. The event scenario involved multiple safety-related component failures and plant conditions warranting a simulated Alert event declaration. The licensee counted this training evolution for evaluation of Emergency Preparedness Drill/Exercise Performance (DEP) Indicators. The inspectors observed the training critique to determine whether the licensee critically evaluated operator performance to identify deficiencies and weaknesses. The inspectors reviewed the event notification forms and DEP indicator results during this period to verify the DEP performance indicators were properly evaluated consistent with Nuclear Energy Institute (NEI) 99-02, “Regulatory Assessment Performance Indicator Guideline,” Rev. 2. Additional documents used for this inspection activity included:

- 2OM-53A.1.E-0, “Reactor Trip or Safety Injection,” Rev. 3
- 2OM-53A.1.E-2, “Faulted Steam Generator Isolation,” Rev. 2
- 2OM-53A.1.E-3, “Steam Generator Tube Rupture,” Rev. 3
- 2OM-53C.4.2.6.4, “Steam Generator Tube Leakage,” Rev. 13
- EPP /1-1b, “Beaver Valley Power Station Unit 2 Emergency Action Levels,” Rev. 6
- Emergency Plan Implementing Procedure (EPIP) 1.1, “Notifications,” Rev. 28
- EPP -16, “NRC Emergency Preparedness Performance Indicator Instructions,” Rev. 4

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 licensee’s access controls to radiologically significant areas.

On October 29 and 30, 2002, the inspectors, on three separate occasions, toured the auxiliary buildings and fuel handling buildings for each unit, the solid radwaste and decontamination buildings for Unit 1, and the recently-established common health physics access control point for both units. At this common control point, the inspectors observed radiation workers logging into the radiologically-controlled area (RCA) on radiological work permits (RWPs) using the new Merlin-Gerin electronic dosimeters and observed radiation workers exiting the RCA and then logging out of their RWPs. The use of personnel dosimetry and the radiological briefings for in-going radiation workers was appropriate. Also, during these walkdowns, the inspectors observed and verified the appropriateness of the posting, labeling, and barricading (as appropriate) of radioactive material, radiation, contamination, high radiation, and locked high radiation areas. Also, on both October 29 and 30, 2002, the inspectors observed the morning health physics status meetings (conducted at 0730 hours each morning) which involve the radiation protection technicians, and are conducted by first-line supervision.

The inspection included a selective review of RWPs, procedures, and documents (as listed in the List of Documents Reviewed attachment) 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 TSs, 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 cumulative year-to-date collective radiation exposure and noted that the actual exposure was below the year-to-date site estimate. The inspectors also noted that the currently projected annual dose was below the original annual estimate in spite of the dose to be incurred due to the upcoming unplanned maintenance outage for the reactor head inspection Unit 1 maintenance outage (1MO2).

On October 28, 30, and 31, 2002, the inspectors met periodically with the Health Physics Specialist for ALARA and with the Senior Health Physics Specialist for ALARA to discuss: a) the current ALARA planning for the upcoming maintenance outage to inspect and clean the reactor head in situ; b) the RWP person-rem estimates; and c) the ALARA review process in use. On the afternoon of October 29, 2002, the inspected observed an outage readiness review meeting for 1MO2 which included a reactor vessel head visual inspection, cleaning, and under head contingency readiness review and a discussion of the ALARA committee job-specific dose reduction presentation. On October 30, 2002, the inspectors observed a site ALARA committee meeting which addressed 1MO2 issues including scaffolding for snubber work, establishment of an alternative containment access briefing area, continued use of containment access permits, the use of closed-circuit television monitors on the containment operating elevation and in the containment access briefing area, and the use of wireless communication headsets by radiation protection personnel in the briefing area and in containment. Also, on this date, the inspectors reviewed the status of selected ALARA reviews for 1MO2 in the RWP office.

The inspectors performed a selective examination of documents (as listed in the List of Documents Reviewed attachment) 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 to determine the accuracy and operability of the instrumentation.

During the inspectors' tours described in Section 2OS1, the inspectors reviewed field instrumentation utilized by health physics technicians, continuous air monitors, hand-held contamination frisking instruments, and personnel contamination and portal monitors to verify current calibrations, performance of appropriate source checks, and operability. The inspectors also noted that the plans to install portal monitors, in addition to the installed personnel contamination monitors at the common exit of the radiologically-controlled area to provide for additional detection efficiency for radioactive contamination, had been implemented. Also, on October 28, 2002, the inspectors met with a radiation protection supervisor to discuss CR 02-06174. This CR discussed the plans for zinc addition at Unit 1 and the potential impact of Zinc-65 on the overall detection efficiency of each of the types of radioactive-contamination-monitoring equipment used at the site versus the detection efficiencies for the current mix of radionuclides.

On October 28, 2002, the inspectors met with the health physicist responsible for the respiratory protection program and discussed the methods used to assure that the qualifications required for individuals authorized to use self-contained breathing apparatus were kept up to date.

The inspectors performed a selective examination of records (as listed in the List of Documents Reviewed attachment) 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 RETS/ODCM Radiological Effluent Occurrences

a. Inspection Scope

On October 31, 2002, the inspectors selectively examined records used by the licensee to identify occurrences involving Radiological Effluent Technical Specification/Offsite Dose Calculation Manual (RETS/ODCM) radiological effluent occurrences. This examination included the time period from the second quarter of 2001 through the first quarter of 2002. This examination was performed against the applicable criteria specified in NEI 99-02, "Regulatory Assessment Performance Indicator Guideline," Rev. 0 (effective date of 28 March 2000), Rev. 1 (effective date of 23 April 2001), and Rev. 2 (effective date of 19 November 2001). The purpose of the examination was to verify that all conditions that met the NEI criteria were recognized and identified as performance indicators (PIs). The inspectors also discussed these records with the two health physicists responsible for the effluent dose program.

The inspectors also performed this selective examination of records (as listed in the List of Documents Reviewed attachment) for regulatory compliance and adequacy. This examination did not identify any problems with the PI accuracy or completeness and thus verified this performance indicator.

b. Findings

No findings of significance were identified.

.2 Reactor Coolant System Identified Leak Rate

a. Inspection Scope

The inspectors reviewed the Unit 1 and Unit 2 PI for unidentified RCS leak rate for the period December 2001 to November 2002. The accuracy of reported data was verified by reviewing selected monthly operating reports, shift operating logs, LERs, and surveillance tests. The inspectors verified the RCS leak rate data reported was consistent with NRC approved guidance, provided in NEI 99-02.

b. Findings

No findings of significance were identified.

.3 Residual Heat Removal System Unavailability

a. Inspection Scope

The inspectors reviewed the Unit 1 and 2 performance indicators for the systems that provide post-accident recirculation and shutdown cooling. The specific systems reviewed included the Unit 1 low head safety injection, recirculation spray, residual heat removal systems and the Unit 2 recirculation spray and residual heat removal systems. Due to the plant specific design, NEI 99-02, Appendix D, "Plant Specific Design Issues," Rev. 2, was used to determine the scope of the data collected. The inspectors verified accuracy of the reported data through reviews of shift technical advisors' logs and shift operator logs for the period December 2001 to November 2002.

b. Findings

No findings of significance were identified.

.4 Reactor Coolant System Specific Activity

a. Inspection Scope

The inspectors reviewed the Unit 1 and Unit 2 PI for RCS specific activity for the period December 2001 through November 2002. The accuracy of reported data was verified by reviewing the results from TS sampling, other chemistry samples of the RCS, and supporting calculations and calculation methodology. The inspectors verified the RCS specific activity data reported was consistent with NRC approved guidance, provided in NEI 99-02, Rev. 2.

b. Findings

No findings of significance were identified.

.5 Safety System Functional Failures

a. Inspection Scope

The inspectors reviewed the Unit 1 and Unit 2 PIs for safety system functional failures to determine whether the NRC approved guidance, provided in NEI 99-02, Rev. 2, was properly implemented. Verification included review of the data collected, PI definitions, data reporting elements, calculational methods, definition of terms, and use of clarifying notes. The inspectors verified accuracy of the reported data through reviews of LERs submitted during the period December 2001 through November 2002.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems

.1 Evaluation and Resolution of No Senior Reactor Operators Present in Control Room

a. Inspection Scope

On November 21, 2002, no senior reactor operator (SRO) was present in the Unit 2 control room for a period of approximately 5 minutes, while the unit operated at full power. Licensee management became aware of this late on November 28. The inspectors reviewed the licensee investigation and corrective actions to this performance issue to determine whether actions, from time of management discovery, were timely and appropriate to preclude recurrence. The issue of having no SRO in the control room and actions during the period of November 21-28, are the subject of a separate inspection activity.

b. Findings

Introduction

The inspectors determined that corrective actions, after station management was informed that there was no SRO present in the Unit 2 control room for a 5-minute period during Mode 1 (at power) operation, were untimely and incomplete. At least one SRO and one reactor operator (RO) are required to be present in the control room during Mode 1 operation to ensure proper reactor safety oversight during the operation of safety related structures, systems, and components. This finding was of very low safety significance (Green) since no additional control room staffing deficiencies occurred during the 3-day period of untimely and incomplete corrective actions.

Description. Station management became aware of the control room SRO staffing issue late on November 28, 2002. The inspectors discussed the issue with Operations Management on December 1. The inspectors were informed that CR 02-10930 was written, one RO from the affected shift had been interviewed, this was an isolated incident reflecting one person's error, and the two effected SROs would be interviewed and/or counseled prior to the next time they stood watch. The CR was initially categorized as a condition adverse to quality, and elevated to a significant condition adverse to quality on December 1.

Operating Manual 48.1.A, "Duties and Responsibilities of the Operations Group," Rev. 1, specifies requirements for control room shift staffing. The FirstEnergy Nuclear Operating Company Quality Assurance Program Manual, Rev. 3, requires, in part, that the corrective action program be implemented to promptly correct conditions adverse to quality. For significant conditions adverse to quality, the cause is to be determined and corrective action implemented to preclude recurrence.

The inspectors determined that, based on information known to the licensee on December 1, this event revealed knowledge deficiencies beyond the one SRO. On November 21, one SRO, two ROs, and one non-licensed operator were all aware that no SRO had been in the control room for 5 minutes. Yet no CR or management notification was initiated until November 28. The inspectors questioned: (1) what actions had been taken to verify all SROs and ROs knew the regulatory requirements for control room staffing; and (2) what plant configuration changes or reactivity manipulations occurred during the 5-minute period. Operations management had not reviewed either issue.

In response to the inspectors' questions, the Unit 2 Operations Manager stated he would write an Operations Night Order addressing control room staffing requirements for all SROs and ROs to read prior to assuming the watch. He also planned to brief the oncoming shifts on this event. A physical compensatory measure was also implemented early on December 2, to prohibit both SROs from leaving the control room at the same time while the reactor was in Mode 1. Early on December 2, the inspectors interviewed several on shift personnel and determined that despite the above actions, two ROs and the shift technical advisor, did not know the regulatory requirements for control room shift staffing. Additionally, several on shift personnel had not read the night order concerning this event. The inspectors concluded that corrective actions from November 28 to December 1 were untimely and inadequate to ensure control room staffing requirements were met. The inspectors discussed these observations with station management on December 2, and reasonable interim corrective actions were then implemented.

Analysis. This issue was not suitable for NRC Significance Determination Process evaluation, but has been reviewed by NRC management and is determined to be a Green finding of very low significance. The finding was greater than minor because absence of SRO oversight during licensed control room operator activities increases the likelihood of human performance errors. Increased human error in turn increases the likelihood of an initiating event and reduces the availability of mitigating systems to respond to an initiating event. Additionally, SRO oversight is requisite for implementing the role of Emergency Director as specified by the site Emergency Plan. Knowledge of SRO control room staffing requirements is important to ensure appropriate oversight of licensed control room activities. This issue was of very low safety significance since no additional control room staffing deficiencies occurred during the 3 day period of untimely and incomplete corrective actions.

Enforcement. 10 CFR 50, Appendix B, Criterion XVI, “Corrective Action,” requires in part that measures be established to assure conditions adverse to quality are promptly corrected. In the case of significant conditions adverse to quality, measures shall ensure that corrective actions is taken to preclude repetition. Operating Manual 48.1.A, “Duties and Responsibilities of the Operations Group,” Rev. 1, specifies requirements for control room shift staffing. The FirstEnergy Nuclear Operating Company Quality Assurance Program Manual, Rev. 3, requires, in part, that the corrective action program be implemented to promptly correct conditions adverse to quality. For significant conditions adverse to quality, the cause is to be determined and corrective action implemented to preclude recurrence. On November 21, 2002, a significant condition adverse to quality existed in that no SRO was present in the Unit 2 control room during Mode 1 operation. Contrary to the above, from November 28 to December 1, 2002, corrective actions were untimely and inadequate to reasonably preclude recurrence of inadequate control room shift staffing. Specifically, actions were not taken to correct licensed operator knowledge deficiencies regarding regulatory requirements for control room shift staffing. This violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: **NCV 50-412/02-07-01**, Untimely and Incomplete Corrective Actions Regarding Inadequate Control Room Staffing.

.2 Evaluation of Unit 1 Cable Tray Mezzanine Area Fire Suppression System Adequacy

a. Inspection Scope

During a self-assessment, the licensee questioned the adequacy of the CO_2 fire protection system for the cable spreading room as a result of their review of the original discharge test performed in 1975. At question was the adequacy of the CO_2 concentration hold times. The code of record for the system installation (National Fire Protection Association [NFPA] 12-1973) specified that the 50 percent extinguishing concentration be maintained for a substantial period of time to assure complete extinguishment but did not include specific hold times.

Subsequent to the 1975 discharge test, the licensee upgraded fire penetration seals, modified dampers, replaced fire door seals, and expected that the CO_2 retention times would be higher than those observed during the 1975 test. No additional testing or engineering analyses were performed at that time to quantify the expected improvements in the concentration hold times. Condition Report 01-0192 was initiated, and included a corrective action to perform additional analyses. During the NRC triennial fire protection inspection Unresolved Item (URI) 50-334/01-05-02 was opened pending NRC review of the results of the additional analyses to be performed by the licensee.

The licensee performed leakage tests to determine the actual leakage of the cable spreading room area envelope and used the leakage as an input to a calculation performed to assess the ability to maintain adequate CO_2 concentration. The licensee also evaluated the effects of the internal room pressure resulting from a CO_2 discharge. This evaluation identified the potential for a higher than desired pressure spike during the discharge, and the licensee implemented a modification to establish a vent path to remove excess air during a discharge.

The engineering analyses included evaluations of CO_2 concentrations following a second discharge, which is within the capability of the system and is specified in plant procedures. The analyses predicted average CO_2 concentrations well above 50 percent with peak average concentrations as high as approximately 78 percent. The average concentrations were predicted to decrease at a rate of approximately 0.5 percent per minute with the vent path established. As a result, the licensee concluded that the extinguishing capability of the CO_2 system was adequate and in accordance with the NFPA code of record.

The inspectors discussed the resolution of this issue with the cognizant licensee engineering personnel and reviewed associated documentation, including test data, engineering analyses, plant procedures, modification documents, and the Updated Fire Protection Appendix R Review Report. The inspectors also performed walkdowns to assess the condition of penetration seals, door seals, fire dampers, and fire protection equipment. A walkdown was also performed to assess the adequacy of the vent path.

b. Findings

Based on a review of the NFPA Code, the engineering analyses, the vent modification, plant procedures and field walkdowns, the inspectors found that the licensee actions were appropriate and comprehensive. No violations of NRC requirements were identified. Unresolved Item 50-334/01-05-02 is closed.

4OA3 Event Follow-up

.1 Unit 1 Manual Reactor Trip due to Turbine Motoring Instrument Failure

a. Inspection Scope

On November 11, 2002, while in the process of shutting down for a planned maintenance outage, Unit 1 operators manually tripped the reactor from 53 percent power in response to a turbine motoring condition (A7-98) alarm. This action was consistent with the associated alarm response procedure. The alarm exists to alert operators of a loss of steam supply to the turbine which could cause the generator to drive the turbine and result in overheating damage to the low pressure and high pressure turbine blading. Operators implemented EOP E-0, "Reactor Trip or Safety Injection," Rev. 2, and cooled down the plant to cold shutdown for the planned maintenance outage. The inspectors reviewed various instruments and sequence of events recorders, and conducted interviews to verify the plant responded as designed. The inspectors also verified the reactor trip was properly reported in accordance with 10 CFR 50.72. The inspectors reviewed the event's risk significance with licensee risk analysts and determined that the conditional core damage probability was very low. No additional NRC reactive response was necessary.

b. Findings

Introduction. Inappropriate application of a differential pressure instrument, lack of preventive maintenance, and ineffective problem identification and resolution led to an unplanned Unit 1 reactor trip. This finding was of very low significance because the issue did not effect the availability of mitigation equipment.

Description. Differential pressure instrument (PDIS-1TB-103) provides early indication of a loss of steam to the turbine and associated potential for turbine damage. A 30-second time delay provides operators with time to assess and remediate the condition prior to an automatic reactor trip. This instrument is normally pegged high due to application and sensitivity considerations. Operators had logged the instrument reading at 53 pounds per square inch differential, which was abnormal since September 2002, but had not initiated corrective action to investigate. After the trip, the Event Review Team (ERT) concluded that the false reading was an indication that the instrument was out of calibration or had failed.

Similar instrument readings were observed in 1999, but had not been properly resolved. Turbine trips cause the instrument to experience a large pressure transient which shortens the instrument life. The ERT determined that the vendor recommends post-trip instrument calibration and a periodic replacement at 5-10 year interval depending on service environment. Unit 1 has experienced a large number of plant trips (11) in the past six years. Unit 2 has different type of instrument which is less susceptible to degradation due to pressure transients. The inspectors determined that failure to identify and resolve the degraded instrument condition directly contributed to the Turbine Motoring Condition alarm and subsequent reactor trip.

Analysis. The inspectors determined the safety significance of this finding was very low (Green) using Inspection Manual Chapter (IMC) 0612, Appendix 'B' and the phase one screening process of IMC 0609, Appendix 'A'. The issue affected equipment performance under the Reactor Safety cornerstone and was more than minor because it caused an initiating event (reactor trip). This finding was of very low significance because the issue did not increase the likelihood that mitigation equipment would be unavailable.

Enforcement. The Turbine Motoring Condition (A7-98) alarm and associated d/p instrument are not subject to the requirements of 10 CFR 50, Appendix B. The inspectors determined that no violation of regulatory requirements occurred **(Finding (FIN) 50-334/02-07-02)**. This event was entered into the licensee's corrective action program as CR 02-10167.

.2 (Closed) Licensee Event Report 50-412/02-03-00 and 01: Calibration Discrepancies in Delta Temperature Tau Time Constants Values Used in the Reactor Protection System

a. Inspection Scope

This licensee event report and its supplement described calibration discrepancies that did not provide for the correct overpower delta temperature (OTDT) lead and lag times for Unit 2 as required by TS 3.3.1.1, "Reactor Trip Instrumentation Setpoints." Specifically, the time constant Tau 4 (lead time) for all three Unit 2 reactor coolant system loops did not comply with TS requirements. As detailed in the supplement to this LER, an extent of condition review of reactor protection system (RPS) dynamic response testing later noted an inconsistency between approved scaling methodology and the test methodology utilized in the maintenance surveillance procedure for the Overpower Delta Temperature (OPDT) rate/lag modules for Beaver Valley Unit 1. This error rendered the Tau 3 (lead time) constant in non-compliance with Beaver Valley Unit 1 TS 3.3.1.1. The extent of condition review also identified that the Tau 7 and K5 constants used in the OPDT reactor protection system channels at Beaver Valley Unit 2 were incorrectly set and thus were not in compliance with Unit 2 TS 3.3.1.1. The inspectors performed an onsite review of the LER and the supplement to verify the event was accurately reported and assess licensee causal assessment and corrective actions.

Introduction. The inspectors determined that deficient setpoint configuration control resulted in incorrect OPDT and OTDT lead/lag constants. These deficiencies affected the mitigating systems cornerstone; specifically functionality of the reactor trip system. The safety significance of this issue was very low because the errors did not result in a loss of any RPS safety function at either unit.

Description. The licensee's root cause investigation identified the causes of the errors to be: 1) an incorrect test set-up caused by a wrong assumed value for the Tau 4 time constant and the Tau7/K5 values during a June 2001 revision to a maintenance surveillance procedure at Unit 2; and, 2) a non-existent/inadequate process to translate, verify and review that design requirements were correctly implemented in calibration procedures early in the operation of Beaver Valley Unit 1, resulting in an incorrect time constant that was never identified.

Analysis. The inspectors determined the safety significance of this finding was very low (Green) using phase one of the significance determination process . Specifically, the inspectors noted that these time constants are only necessary to adjust RPS setpoints when the units are operating in highly dynamic conditions, a situation which both units experience only during certain accident scenarios or severe power transients with a very high rate-of-change. This licensee-identified finding screened to Green because the errors individually and collectively did not result in a loss of any RPS safety function at either unit based on subsequent engineering analysis. The LER and its supplement described the analyses performed that demonstrated that the conclusions in the UFSAR Chapter 15, “Accident Analyses,” regarding the ability of Unit 2 to mitigate licensing basis events remained valid and that the safety impact was minimal. The Unit 1 time constant error had negligible impact on plant safety because plant conditions in the past would have provided equivalent or conservative operation as compared to the as-found Tau 3 setting.

Enforcement. The inspectors determined that the event involved a violation of 10 CFR 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings” in that procedures did not contain appropriate RPS quantitative acceptance criteria. This licensee identified violation is documented in section 4OA7 of this report.

4OA5 Other

.1 NRC Temporary Instruction (TI) 2515/150, “Reactor Pressure Vessel Head and Vessel Head Penetration Nozzles (NRC Bulletin 2002-02)

a. Inspection Scope

Station personnel shut down Unit 1 on November 12 to inspect the material condition of the reactor pressure vessel (RPV) head and associated penetrations and identify whether indications of leakage or wastage were present. Engineers performed Visual Examination Technology Level II (VT-II) inspections with the aid of robot positioned cameras and recording media. The inspectors observed portions of RPV inspection, interviewed test engineers, and performed the bare metal visual inspection portion of NRC TI 2515/150. The inspectors evaluated personnel qualifications, data collection, data assessment methods, and the Beaver Valley Unit 1 1M02 Control Rod Drive Mechanism (CRDM) Inspection Report, dated November 17, 2002.

b. Findings

(1) All examiners were properly qualified to VT Level II or better standards, as specified in Quality Services Procedure 2.3, “Written Practice for Qualification and Certification of Nondestructive Examination and Testing Personnel,” Rev. 6.

(2) The RPV head inspection was performed in accordance with licensee approved vendor procedures and WO 02-19466. The scope of the examination included all 56 CRDM penetrations, the RPV vent line penetration, and 100 percent of the reactor vessel head external surface area (beneath the installed insulation). An as-found inspection of all areas listed, including each quadrant surrounding each individual penetration was conducted. Afterwards, a low pressure warm water

solution was used to rinse and clean the RPV head. Minor dust, erosion, or debris which could possibly mask material defects were identified in the vicinity of eight CRDM penetrations (penetrations Nos. 30, 33, 36, 41, 47, 53, 59, and 65). An as-left visual examination was performed on each of these eight penetrations.

(3) The examination identified and properly dispositioned three material deficiencies (penetrations Nos. 53, 59, and 65) attributed to previous Conoseal leakage.

(4) The examination technique and quality met the intent of the visual examination portion of NRC TI 2515/150 to detect evidence of primary water stress corrosion cracks as described in NRC Bulletin 2002-02, “Reactor Pressure Vessel Head and Vessel Head Penetration Nozzle Inspection Programs.”

(5) The general visual condition of the RPV was head was good. Indications of previous Conoseal No. 2 leakage was evident in the vicinity of penetrations Nos. 53, 59, and 65. There was no indication of active leakage at the Conoseals or any RPV head penetrations. Minor dirt, paint flaking, and boron crystals were present prior to the warm water rinse of the RPV head. The cameras with use of robotic crawlers were able to provide clear video coverage of 100 percent of the RPV head and penetration area.

(6) Small boric acid crystals were visible and attributed to the previous Conoseal or refueling cavity seal leakage. These sources of leakage were previously repaired and there was no indication of continued leakage. The as-found visual inspection determined that none of the RPV head penetrations displayed boric acid accumulations of a configuration indicative of leakage from a CRDM penetration.

(7) Eight CRDM penetrations had minor debris present [as described in (2) above] which could potentially inhibit the quality of the visual examination. Each of these eight CRDM penetrations were successfully reinspected following the warm water RPV head rinse to remove the debris. None of the penetrations indicated active boric acid leakage or required repair. Two of the penetrations (Nos. 53 and 65) had approximately 1/8-inch depth of corrosion in the RPV head surrounding the penetration. This was due to the previously mentioned (and no longer active) Conoseal leak. This corrosion was minor and is well within the acceptance limits for the RPV head.

.2 NRC Temporary Instruction 2515/148, “Inspection of Nuclear Reactor Safeguards Interim Compensatory Measures ” Rev. 1

a. Inspection Scope

An audit of the licensee’s performance of the interim compensatory measures imposed by the NRC’s Order Modifying License, issued February 25, 2002, was completed in accordance with the specifications of NRC Inspection Manual, “Temporary Instruction 2515/148,” Rev. 1, Appendix A, dated September 13, 2002.

b. Findings

No findings of significance were identified.

4OA6 Management Meetings

.1 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 January 10, 2003. The licensee acknowledged the findings presented.

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

.2 Site Management Visit

On December 11-13, 2002, Mr. A. Randolph Blough, NRC Region I Director, Division of Reactor Projects; Mr. Jim Clifford, NRC Region I Deputy Director, Division of Reactor Projects, and Mr. John Rogge, NRC Region I Chief, Reactor Projects Branch 7, toured Beaver Valley Power Station and met with station personnel to review plant performance.

4OA7 Licensee-Identified Violations

The following violations of very low safety significance (Green) were identified by FENOC (as discussed in section 1R14.2 and 4OA3.2 of this inspection report) and were violations of NRC requirements which meet the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as an NCV:

Requirements Licensee Failed to Meet

1. Technical Specification 6.8.1.2 requires at least one EDG be operable with the reactor in Mode 6 (refueling). With less than one EDG operable, immediately suspend all operations involving core alterations. Contrary to the above, from February 14 to 18, 2002, no Unit 2 EDG was operable. During this period, operators performed core alterations in that they refueled the core as described in CR 02-1504. Primarily due to the quality and content of various 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 is being treated as an NCV (Section 1R14.2).

2. 10 CFR 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings,” requires in part that procedures shall include appropriate quantitative acceptance criteria for determining that important activities have been satisfactorily accomplished. Contrary to this requirement, procedures 1MSP-6.38-I, “T-RC412 Delta T- Tavg Protection Instrument Channel 1 Calibration,” Rev. 15, and 2 MSP-6.38-I, “Reactor Coolant Temperature Loop 2RCS-T14 Tavg Protection Channel 1 Calibration,” Rev. 14, failed to include correct settings for the OTDT lead and lag RPS time constants, resulting in non-compliance with Technical Specification 3.3.1.1 requirements at Units 1 and 2, as documented in CRs 02-

01679, 02-02037, and 02-05961. However, because the errors individually and collectively did not result in a loss of any RPS safety function, this violation is of very low safety significance and is being treated as an NCV (Section 4OA3.2).

ATTACHMENT 1
SUPPLEMENTAL INFORMATION

a. Key Points of Contact

Licensee Personnel:

M. Bezilla	Vice President
T. Cosgrove	Director, Work Management
R. Donnellon	Director, Maintenance
L. Freeland	Manager, Nuclear Regulatory Affairs & Corrective Actions
J. Lash	Plant General Manager
M. Pearson	Director, Nuclear Services
P. Sena	Manager, Nuclear Operations
F. von Ahn	Director, Plant Engineering

b. List of Items Opened, Closed and Discussed

Opened and Closed

50-412/02-07-01	NCV	Untimely and Incomplete Corrective Actions Regarding Inadequate Control Room Staffing (Section 4OA2.1)
50-334/02-07-02	FIN	Ineffective Problem Identification and Resolution of Degraded Pressure Instrument Results in Manual Reactor Trip (Section 4OA3.1)

Closed

50-412/02-03	LER	Calibration Discrepancies in Delta Temperature Tau Time Constants Values Used in the Reactor Protection System (Section 4OA3.2)
50-412/02-03-01	LER	Calibration Discrepancies in Delta Temperature Tau Time Constants Values Used in the Reactor Protection System (Section 4OA3.2)
50-412/02-02	LER	Tagout Reduces Ability of Emergency Diesel Generator of Respond to Loss of Offsite Power (Section 4OA5)
50-334/01-05-02	URI	Capability of Cable Tray Mezzanine CO_2 System to Suppress Deep-Seated Fires (Section 4OA2.2)

c. List of Documents Reviewed

1RO1: Adverse Weather Protection

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

1RO4: Equipment Alignments

Procedures:
1OM-30.3.B.1, River Water Valve List, Rev. 30
1OM-1.2B, Setpoints, Rev. 9
1OM Figure Number 30-1 through 3-6
1OM Figure Number 1-1

1R05: Fire Protection

Procedures:
AM-1900, Fire Protection, Rev. 1
Unit 1 Updated Fire Protection Appendix R, Rev. 16
Unit 2 Fire Protection Safe Shutdown Report, Addendum 18
Emergency Squad and Fire Brigade Drill, Rev. 0

1R11: Licensed Operator Requalification

Procedures:
2002 Annual Requalification Exam Unit 1 Drill 30, Rev. 2A
2002 Annual Requalification Exam Unit 2 Drill 27, Rev. 0B
2002 Annual Requalification Exam Unit 2 Drill 30, Rev. 0A
1OM-53A.1.E-0, Reactor Trip or Safety Injection, Rev. 2
1OM-53A.1.E-2, Faulted Steam Generator Isolation, Rev. 0
1OM-53C.4.1.6.7, Excessive Primary Plant Leakage, Rev. 0
2OM-53A.1.E-0, Reactor Trip or Safety Injection, Rev. 3
2OM-53A.1.E-2, Faulted Steam Generator Isolation, Rev. 2
2OM-53A.1.E-3, Steam Generator Tube Rupture, Rev. 3
2OM-53C.4.2.6.4, Steam Generator Tube Leakage, Rev. 13
EPP/1-1a, Beaver Valley Power Station Unit 1
Emergency Action Levels, Rev. 6
EPP /1-1b, Beaver Valley Power Station Unit 2 Emergency Action Levels, Rev. 6
NUREG 1021, Rev.8, Supplement 1, Operator Licensing Examination Standards for Power Reactors
Inspection Procedure Attachment 71111.11, Licensed Operator Requalification Human Performance
NRC Manual Chapter 0609, Appendix 1, Operator Requalification Human Performance Significance Determination Process

1R12: Maintenance Rule Implementation

Procedures:
10 CFR 50.65
10 CFR 50.65(a)(1) and (a)(2)
CR 01-1866, Motor driven auxiliary feed pump (FW-P-3B) elevated inboard motor earing temperature
CR 02-00585, Steam leakage on auxiliary feed pump turbine 1FW-P-2
CR 02-10899, Governor Valve, GO-1MS-POS broken LVDT (Linear Variable Differential Transformer) rod

1R13: Maintenance Risk Assessment and Emergent Work Control

Procedures:
½-AM-2033, Risk Management Program, Rev. 1
NPDAP 7.12, Non-outage Planning, Scheduling, and Risk Assessment, Rev. 11
NPDAP 8.30, Maintenance Rule Program, Rev. 6
Conduct of Operations Procedure 1/2OM-48.1.I, Technical Specification Compliance, Rev. 9.

1R19: Post-Maintenance Testing

Procedures:
2OST-30.6B, Service Water Pump 2SWS*P21C Test on Train 'B' Header, Rev. 8
1OST-1.10, Cold Shutdown Valve Exercise Test, Rev. 22
1OST-10.4, Residual Heat Removal System Valve Exercise, Rev. 11
1OST-10.5, Leak Test [MOV-1RH-700 and 701], Rev. 8
1OST-16.2, Supplementary Leak Collection and Release Test for Exhaust Through the Main Filter Bank - Train B, Rev. 7
Partial 2OST-1.11A, Safeguards Protection System Train 'A' Blockable Test, Rev. 9
2OST-30.6B, Service Water Pump [2SWS*P21C] Test on Train B Header, Rev. 8
1OM-50.4.L, Plant Heatup From Node 5 to Mode 3, Rev. 5
1OM-50.4.D, Reactor Startup From Mode 3 to Mode 2, Rev. 39
1OM-52.4.A, Raising Power From 5 percent to Full Load Operation, Rev. 41

1R22: Surveillance Testing

Procedures:
2OST-33.10A, Deluge Valve Test, Rev. 10
1OST-36.1, Diesel Generator No. 1 Monthly Test, Rev. 34
1OM-36.4.AJ, No. 1 Diesel Generator 24 Hour Run, Rev. 0
2OM-36.4.AI, Emergency Diesel Generator [2EGS*EG2-1] 24 Hour Run, Rev 0
2MSP-105.1, Solid State Protection System Train 'B' Bi-Monthly Test, Rev. 16
1OST-13.1, Quench Spray Pump [1QS-P-1A] Test, Rev. 22

1R23: Temporary Plant Modifications

Procedures:
TM 2-02-18, Removal of internals of check valve 2FPW-163L
TM 1-02-16, Leak repair of 1MS-81, 1B steam generator residual heat release check valve

1EP6: Drill Evaluation

Procedures:
2OM-53A.1.E-0, Reactor Trip or Safety Injection, Rev. 3
2OM-53A.1.E-2, Faulted Steam Generator Isolation, Rev. 2
2OM-53A.1.E-3, Steam Generator Tube Rupture, Rev. 3
2OM-53C.4.2.6.4, Steam Generator Tube Leakage, Rev. 13
EPP /1-1b, Beaver Valley Power Station Unit 2 Emergency Action Levels, Rev. 6
Emergency Plan Implementing Procedure (EPIP) 1.1, "Notifications," Rev. 28
EPP -16, NRC Emergency Preparedness Performance Indicator Instructions, Rev. 4

2OS1: Access Control to Radiologically Significant Areas

Procedures:
RWP 102-1078, Rev. 0, Silica reduction project
RWP 202-2067, Rev. 0, Repair grease seals on fuel transfer canal upender winch
RWP 102-6007, Rev. 0, Reactor head inspections
RWP 102-6010, Rev. 0, Refuel operations, disassembly/reassembly
RWP 102-6015, Rev. 0, Boric acid walkdowns
RWP 102-6020, Rev. 0, Disconnect/reconnect reactor head thermocouples
Procedure ½-HPP-3.08.001, Rev. 0, Radiological work permit
Procedure RP 2.4, Rev. 6, Area posting
Revised BVPS policy on Electronic Alarming Dosimeter "alarm augmentation"

2OS2: ALARA Planning and Controls

½-HPP-3.08.001, Rev. 0, Radiological work permit
½-HPP-3.08.005, Rev. 0, ALARA review
RP 8.11, Rev. 4, Respiratory protection ALARA evaluation
ALARA review 02-1-03 Refuel operations - disassembly/reassembly (RWP 102-6010)
ALARA review 02-1-04 Reactor head inspections (RWP 102-6007)
ALARA review 02-1-10 Boric acid walkdowns (RWP 102-6015)
ALARA review 02-1-11 Disconnect/reconnect reactor head thermocouples (RWP 102-6020)
Actual vs projected cumulative dose/2002 year-to-date exposure summary
Reactor head inspection ALARA plan for 1MO2
1MO2 RWP person-rem estimate summary (12.459 total as of October 30, 2002)
Site ALARA committee meeting minutes for September 23 and October 9, 16, and 25, 2002
Unit 2 ninth refueling outage ALARA report

2OS3: Radiation Monitoring Instrumentation and Protective Equipment

Health Physics Manual, Appendix 6, Rev. 5, Respiratory protection program
Respirator fit program device issue report dated October 18, 2002

4OA1: Performance Indicator (PI) Verification

Procedures:

Monthly projected dose assessment results for radioactive liquid and gaseous effluent releases
Quarterly projected dose assessment results for radioactive liquid and gaseous effluent releases
LERs, CRs, and corrective actions

Associated Procedures:
Procedure ½-HPP-3.0.005, Rev. 0, Radioactive waste discharge authorization-liquid, computer calculation method
Procedure ½-HPP-3.06.006, Rev. 0, Batch radioactive discharge authorization, gas, computer calculation method
Procedure RAS-DG-005 NRC PI desk guide, Rev. 5, July 19, 2002
Documentation and data review forms for RETS/ODCM radiological effluent occurrences
Self-assessment - BVPS effluent data comparison (BV-SA-02-20)

4OA2: Indentification and Resolution of Problems

Procedures

10M-44E.4.Z	Switchgear Area Cooling System Startup
10M-33.4.AAN	Alarm Response Procedure for Cable Tray Mezzanine Fire
10M-56B.3.B.2	Tab 2 - CS-1 Cable Tray Mezzanine Pre-Fire Plan Strategy

Calculations

8700-DMC-1445	CO2 Concentration Versus Time in the Unit 1 Cable Tray Mezzanine

Condition Reports

02-05665	Potential Over pressurization of the Unit 1 Cable Tray Mezzanine

Drawings

8700-RM-444E-3 Valve Operation Diagram - Switchgear Ventilation

Engineering Change Packages

02-0514-01 Modification to Fire Damper 1VS-D-259
Deep-Seated Fires (Section 4OA2.2)

d. List of Acronyms

1MO2	Unit 1 Maintenance Outage 2
ADM	Nuclear Power Administrative Manual
ALARA	As Low As Reasonably Achievable
ASME	American Society of Mechanical Engineers
BCO	Basis for Continued Operation
CFR	Code of Federal Regulations
CR	Condition Report
CRDM	Control Room Drive Mechanism
DCP	Design Change Package
DEP	Drill Exercise Performance
EP	Emergency Preparedness
EPIP	Emergency Preparedness Implementing Procedure
EPP	Emergency Preparedness Procedure
ERT	Event Review Team
FENOC	FirstEnergy Nuclear Operating Company
IMC	Inspection Manual Chapter
JPM	Job Performance Measure
LER	Licensee Event Report
LVDT	Linear Variable Differential Transformer
MSP	Maintenance Surveillance Procedure
NCV	Non-cited Violation
NEI	Nuclear Energy Institute
NFPA	National Fire Protection Association
NPDAP	Nuclear Power Division Administrative Procedure
NRC	Nuclear Regulatory Commission
NUREG	NRC Technical Report Designation
ODCM	Offsite Dose Calculation Manual
OM	Operating Manual
OS	Occupational Radiation Safety
OST	Operational Surveillance Test
PARS	Publicly Available Records
PI	Performance Indicator
PMT	Post Maintenance Test
PORV	Power Operated Relieve Valve
psig	Pounds per Square Inch
RCA	Radiologically Controlled Area
RCS	Reactor Coolant System
RETS	Radiological Effluent Technical Specification
RO	Reactor Operator
RPS	Reactor Protection System
RPV	Reactor Pressure Vessel
RWP	Radiological Work Permit

SDP	Significance Determination Process
SLCRS	Supplementary Leak Collection and Release System
SRO	Senior Reactor Operator
SSC	Structures, Systems, and Components
SSST	System Station Service Transformer
TER	Technical Evaluation Report
TI	Temporary Instruction
TM	Temporary Modification
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
VT	Visual Examination Technology
WO	Work Order