July 22, 2004

Mr. Christopher M. Crane
President and CNO
Exelon Nuclear
Exelon Generation Company, LLC
200 Exelon Way KSA 3-E
Kennett Square, PA 19348

SUBJECT: PEACH BOTTOM ATOMIC POWER STATION - NRC INTEGRATED INSPECTION REPORT 05000277/2004003 AND 05000278/2004003

Dear Mr. Crane:

On June 30, 2004, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at the Peach Bottom Atomic Power Station, Units 2 and 3. The enclosed integrated inspection report documents the inspection findings, which were discussed on July 8, 2004, with Mr. Bob Braun and other members of your staff.

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.

The report documents two self-revealing findings of very low safety significance (Green). Both findings were determined to involve violations of NRC requirements. However, because of their very low safety significance and because they were entered into your corrective action program, the NRC is treating these findings as non-cited violations (NCVs), in accordance with Section VI.A of the NRC's Enforcement Policy. Additionally, a licensee-identified violation, which was determined to be of very low safety significance, is listed in Section 4OA7 of this report. If you contest any NCVs in this report, 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, D.C. 20555-0001; with copies to the Regional Administrator, Region I; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, D.C. 20555-0001; and the NRC Resident Inspector at the Peach Bottom facility.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response (if any) will be 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).

If you have any questions, please contact me at 610-337-5209.

Sincerely,

/RA/
Mohamed Shanbaky, Chief
Projects Branch 4
Division of Reactor Projects

Docket Nos.: 50-277, 50-278
License Nos.: DPR-44, DPR-56

Enclosure: Inspection Report 05000277/2004003 and 05000278/2004003
w/Attachment: Supplemental Information

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Plant Manager, Peach Bottom Atomic Power Station
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REGION I

Docket Nos.:	50-277, 50-278, 72-29
License Nos.:	DPR-44, DPR-56
Report No.:	05000277/2004003 and 05000278/2004003
Licensee:	Exelon Generation Company, LLC Correspondence Control Desk P.O. Box 160 Kennett Square, PA 19348
Facility:	Peach Bottom Atomic Power Station Units 2 and 3
Location:	1848 Lay Road Delta, Pennsylvania
Dates:	April 1, 2004 through June 30, 2004
Inspectors:	C. Smith, Senior Resident Inspector D. Schroeder, Resident Inspector G. Johnson, Operations Engineer R. Nimitz, Senior Health Physicist J. Wray, Health Physicist
Approved by:	Mohamed M. Shanbaky, Chief Projects Branch 4 Division of Reactor Projects

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SUMMARY OF FINDINGS

IR 05000277/2004003, 05000278/2004003; 04/01/2004 - 06/30/2004; Peach Bottom Atomic Power Station, Units 2 and 3; Operability Evaluations and Post-Maintenance Testing.

The report covered a 13-week period of inspection by resident inspectors and announced inspections by a regional senior health physicist, health physicist, and an operations engineer. Two Green non-cited violations (NCVs) were identified. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609, “Significance Determination Process” (SDP). Findings for which the SDP does not apply may be Green or be assigned a severity level after 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. NRC-Identified and Self-Revealing Findings

Cornerstone: Mitigating Systems

- Green. A self-revealing non-cited violation (NCV) of 10 CFR Part 50, Appendix B, Criterion III, “Design Control,” was identified. Specifically, design changes made to the high pressure service water (HPSW) motor-operated valve (MOV) on the residual heat removal (RHR) heat exchanger discharge restricted HPSW flow in the affected RHR loop. HPSW flow in this loop was reduced below the design basis flow. The HPSW design basis flow is used to verify RHR heat exchanger operability.

  The finding is considered more than minor, in that the issue was associated with the design control attribute of the mitigating systems cornerstone. The cornerstone objective was affected because improper control of the design change to MO-3-10-89D reduced HPSW flow through this loop below the design basis flow of 4500 gpm. The finding was evaluated using Appendix A of NRC IMC 0609, “Significance Determination of Reactor Inspection Findings for At-Power Situations.” The inspectors concluded that this issue is of very low safety significance since the safety function was maintained.

  The inspectors identified that a contributing cause of the finding was related to the problem identification and resolution cross-cutting area, in that Design Engineering personnel did not adequately resolve known problems with the HPSW MO-89 series valves. (Section 1R15).

- Green. A self-revealing non-cited violation (NCV) of Technical Specification 5.4.1, “Administrative Controls - Procedures,” was identified for inadequate Unit 2 high pressure coolant injection (HPCI) turbine maintenance procedures. The procedures did not contain adequate controls to prevent the mis-positioning of the governor bearing oil supply valve during post-maintenance testing. As a result, oil flow to the bearing was interrupted. Damage to the turbine bearing and rotor rendered the machine inoperable and required the bearing and rotor to be replaced, resulting in unplanned HPCI system unavailability.

This finding is more than minor because, if left uncorrected, it would become a more significant safety concern. The finding affected the mitigating systems cornerstone equipment reliability attribute. The failure of HPCI turbine bearing resulted in a loss of high pressure injection system safety function; therefore, a Phase 2 Significance Determination Process (SDP) was required. A Phase 3 SDP was required to assess the increased risk due to large early release frequency. The Phase 3 SDP determined this issue to be of very low safety significance.

A contributing cause to the HPCI turbine failure was related to the problem identification and resolution cross-cutting area. Specifically, Exelon failed to adequately incorporate relevant operating experience into the design, maintenance, and operation of the HPCI lubricating oil system. (Section 1R19)

B. Licensee-Identified Violations

A violation of very low safety significance, which was identified by Exelon, has been reviewed by the inspectors. Corrective actions taken or planned by Exelon have been entered into the licensee's corrective action program. This violation and corrective actions are listed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status

Unit 2 began this inspection period operating at approximately 100 percent power and remained at or near that power level except for brief periods of planned testing.

Unit 3 began this inspection period operating at approximately 100 percent power and remained at or near that power level except for brief periods of planned testing.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R04 Equipment Alignment (71111.04 - 4 Samples)

a. Inspection Scope

Partial System Walkdowns (71111.04Q). The inspectors performed partial system walkdowns during this inspection period to verify system and component alignments and to note any discrepancies that would impact system operability. The inspectors verified selected portions of redundant or backup systems/trains were available while a system was out of service. The inspectors reviewed selected valve positions, electrical power availability, and the general condition of major system components. This inspection activity represented four samples. The partial walkdowns included the following systems:

- Unit 3 HPCI system with reactor core isolation coolant (RCIC) system out of service for planned maintenance the week of April 19, 2004
- Emergency cooling water (ECW) system with ‘B’ emergency service water (ESW) out of service on April 19, 2004
- Outer screen structure during periods of high river water debris the week of May 10, 2004
- Unit 2 RCIC with Unit 2 HPCI out of service on May 10, 2004

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05 - 7 Samples)

1. Routine Plant Area Tours (71111.05Q)

a. Inspection Scope

The inspectors reviewed the fire protection plan, Technical Requirements Manual, and the respective pre-fire action plan procedures to determine the required fire protection design features, fire area boundaries, and combustible loading requirements for the areas examined during this inspection. The inspectors then performed walkdowns of the following areas to assess control of transient combustible material and ignition sources, fire detection and suppression capabilities, fire barriers, and any related compensatory measures. This inspection activity represented seven samples. The following fire areas were reviewed:

- Diesel driven fire pump room on June 9, 2004
- Motor driven fire pump room on June 9, 2004
- Auxiliary boiler house fire area on May 23, 2004
- Diesel generator building fire area on May 23, 2004
- Unit 2 reactor feed pump turbine/chiller area on June 30, 2004
- Unit 3 reactor building 135' elevation control rod drive on June 30, 2004
- Unit 3 emergency battery and switchgear rooms on June 30, 2004

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures (71111.06 - 1 Sample)

1. External Flood Protection

a. Inspection Scope

The inspectors reviewed the station's external flood analysis, flood mitigation procedures, and design features to verify whether they were consistent with the Peach Bottom design requirements and industry standards. The inspectors walked down selected risk significant plant areas, including the high pressure service water and diesel generator buildings. The inspectors evaluated the condition and adequacy of room flood detectors, sump pumps, sump level alarm circuits, watertight doors, drainage from manholes, and other flood protection design features. The inspectors assessed whether these flood protection design features, for equipment located below the postulated flood levels, were adequate and operable. During the walkdowns, the inspectors also verified whether there were any unidentified or unanalyzed sources of flooding, including holes and un-sealed penetrations in floors and walls. This inspection activity represented one sample.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11)

1. Simulator Evaluation (71111.11Q - 2 Samples)

a. Inspection Scope

The inspectors observed two sessions of licensed operator requalification training activities. On April 13, 2004, the inspectors observed a training scenario involving operator response to risk significant offsite electrical grid emergencies. On May 26, 2004, the inspectors observed a training scenario involving operator response to a reactor scram and reactor recirculation pump trip. During both sessions, the inspectors observed the crew's performance, including the ability to take safe and timely action, alarm response, procedure usage, timely control board operation, supervisory oversight, and group dynamics. The inspectors observed the evaluator's critique following the training session. This activity represented two samples.

b. Findings

No findings of significance were identified.

2. Requalification Examination (71111.11B - 1 Sample)

a. Inspection Scope

During the week of March 15, 2004, an in-office review of Requalification Examination administration was conducted.

The following inspection activities were performed using NUREG-1021, Rev. 9, "Operator Licensing Examination Standards for Power Reactors," Inspection Procedure Attachment 71111.11, "Licensed Operator Requalification Program," and Appendix A, "Checklist for Evaluating Facility Testing Material."

The training department was contacted by phone to discuss recent examination results and any security issues during the exam preparation or administration. A potential exam security issue was reviewed to confirm that re-issuing the suspected exam had resolved the issue.

A review of unusual or atypical conditions that (may have) occurred during the testing cycle was completed. The inspector verified that an RO who had a medical problem and could not complete the examinations, was properly removed from licensed duties (administratively) until he can take the exam(s). A follow-up call on May 26, 2004, confirmed the individual is still on administrative "hold."

The results of the annual operating tests for 2004 were reviewed (in office) for grading. An assessment of whether pass rates are consistent with the guidance of NUREG-1021, Revision 9, “Operator Licensing Examination Standards for Power Reactors,” and NRC Manual Chapter 0609, Appendix I, “Operator Requalification Human Performance Significance Determination Process (SDP),” was also performed. The SDP review verified the following:

- Crew pass rate was greater than 80%. (Pass rate was 90%)
- Individual pass rates on the written exam were greater than 80%. (Pass rate was 98.3%)
- Individual pass rates on the job performance measures of the operating exam were greater than 80%. (Pass rate was 100%)
- More than 75% of the individuals passed all portions of the exam. (91% of the individuals passed all portions of the examination)

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12Q - 3 Samples)

a. Inspection Scope

The inspectors reviewed the follow-up actions for issues identified on systems, structures, or components (SSCs) and the performance of these SSCs, to assess the effectiveness of Exelon’s maintenance activities. This inspection activity represented three samples. The following equipment performance issues were reviewed:

- Loss of the 343 startup source on April 25, 2004
- Fire protection water sprinkler actuation circuit failures on May 27, 2004
- Unit 2 rod block monitor system failure on June 21, 2004

The inspectors verified that problem identification and resolution of these issues had been appropriately monitored, evaluated, and dispositioned in accordance with Exelon’s procedures and the requirements of 10 CFR 50.65, “Requirements for Monitoring the Effectiveness of Maintenance.” In addition, the inspectors reviewed selected SSC classification, performance criteria and goals, and corrective actions to verify that the actions were reasonable and appropriate.

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessments and Emergent Work Evaluation (71111.13 - 7 Samples)

a. Inspection Scope

The inspectors reviewed Exelon's risk evaluations and contingency plans for selected planned and emergent work activities to verify that appropriate risk evaluations were performed and to assess Exelon's management of overall plant risk. The inspectors compared the risk assessments and risk management actions against the requirements of 10 CFR 50.65(a)(4) and the recommendations of NUMARC 93-01 Section 11, "Assessment of Risk Resulting from Performance of Maintenance Activities." The inspectors verified that risk assessments were performed when required and appropriate risk management actions were identified. This inspection activity represented seven samples.

The inspectors attended planning meetings and discussed the risk management of the activities with operators, maintenance personnel, system engineers, and work coordinators to verify that risk management action thresholds were identified correctly. The inspectors also verified that appropriate implementation of risk management actions were performed. The following planned and emergent work activities were reviewed:

- Unit 3 'A' reactor recirculation pump circuit setter planned maintenance on April 15, 2004
- Unit 3 RCIC system outage with 'B' ESW pump unavailable on April 19, 2004
- Unit 2 HPCI system outage and expanded work scope the weeks of May 9 and May 16, 2004
- 'A' ESW and emergency cooling tower maintenance on June 7, 2004
- E4 emergency diesel generator (EDG) surveillance testing with emergent switchyard system lightning strikes on June 15, 2004
- E4 EDG maintenance and emergent switchyard system maintenance on June 23, 2004
- E4 EDG planned maintenance and 'B' control room emergency ventilation testing on June 25, 2004

In addition, the inspectors reviewed the assessed risk configurations against the actual plant conditions and any in-progress evolutions or external events to verify that the assessments were accurate, complete, and appropriate for the issues. The inspectors performed control room and field walkdowns to verify that compensatory measures identified by the risk assessments were appropriately performed.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15 - 6 Samples)

1. Unit 3 ‘D’ High Pressure Service Water Flow Restriction

a. Inspection Scope

On June 9, 2004, during operability testing of the 3D HPSW loop, the specified flow rate of 4500 gpm was not attained. Investigation of the low flow condition revealed that the 3D RHR heat exchanger discharge valve had been replaced in June 2003 with a different style valve which had higher flow resistance than the original valve. This condition revealed itself when the 3B HPSW subsystem was blocked for planned maintenance. This blocking stopped flow bypassing through the leaking 3B HPSW RHR heat exchanger discharge valve. The inspectors reviewed the apparent cause evaluation, operability determination, and extent of condition associated with this event. This inspection activity represented one sample.

b. Findings

Introduction. A self-revealing non-cited violation (NCV) of 10 CFR Part 50, Appendix B, Criterion III, “Design Control,” was identified. Specifically, design changes made to the HPSW motor operated valve (MOV) on the RHR heat exchanger discharge restricted HPSW flow in the affected RHR loop. HPSW flow in this loop was reduced below the design basis flow. The HPSW design basis flow is used to verify RHR heat exchanger operability.

Description. In June 2003, MO-3-10-89D was replaced with a valve of significantly higher pressure drop. This was done using ECR 96-4115, which approves the use of a particular cage and plug design valve for use in MO-2/3-10-89 series valves. Four of these valves were slotted skirt type disk valves, used for throttling, and four were standard globe valve disk type valves. The Engineering Change Request (ECR) states that “Technical comparison of flow, pressure drop, and CV calculations are provided in Attachment 1, showing the new valve and trim kit meet or exceed the performance of the original valve.” The new style valve actually has a significantly higher pressure drop than the standard globe valve disk type valve, the type originally installed in MO-3-10-89D. This was previously identified in ECR 96-1913, which required the removal of one of the three downstream restricting orifice plates to compensate for the higher pressure drop across the valve. ECR 96-4115 omitted this important detail, leaving all three restricting orifice plates installed.

The post maintenance test did not identify this condition because the installed HPSW flow meter measures the combined flow through the B and D loops. Excessive leakage through the idle 3B HPSW subsystem during surveillance testing masked the degraded flow for the 3D HPSW subsystem until the 3B HPSW subsystem was isolated for maintenance. The low flow condition was identified on June 9, 2004. Corrective action to restore proper design flow through this loop is to remove one of the three restricting orifice plates installed in this loop, an action specified in ECR 96-1913.

Analysis. Exelon’s failure to adequately control the design change associated with the replacement of MO-3-10-89D is considered a performance deficiency since Exelon’s design change program is expected to properly evaluate design changes in accordance with 10 CFR 50, Appendix B, Criterion III. Traditional enforcement does not apply because the issue did not have any safety consequence or potential for impacting the NRC's regulatory function and was not the result of any willful violation of NRC requirements or Exelon's procedures. The finding is considered more than minor in that the issue was associated with the design control attribute of the mitigating systems cornerstone and affected the objective of this cornerstone because improper control of the design change to MO-3-10-89D reduced HPSW flow through this loop below the design basis flow of 4500 gpm. The finding was determined to be a Green finding of very low safety significance using Phase I of the SDP, since the finding does not contribute to the likelihood of a system loss-of-coolant accident (LOCA) initiator, does not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions will not be available, and it does not increase the likelihood of a fire or flood. The RHR loop affected by the design change was still capable of performing its safety function and did not impact operability of this heat exchanger. The inspectors identified that a contributing cause of the finding was related to the problem identification and resolution cross-cutting area, in that Design Engineering personnel did not adequately resolve known problems with the HPSW MO-89 series valves.

Enforcement. 10 CFR 50, Appendix B, Criterion III, "Design Control," requires design changes, including field changes, shall be subject to design control measures commensurate with those applied to the original design. Design control measures to be in place shall provide for verifying or checking the adequacy of design. Contrary to the above, design changes to the HPSW system, as determined in 1996, were not reviewed for adequacy prior to the installation of a replacement valve for MO-3-10-89D, installed in June 2003. Because this finding is of very low safety significance and has been entered into Exelon's corrective action program (CR 227081), this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: **NCV 05000278/2004003-01**, **Design Changes Made to the High Pressure Service Water Motor Operated Valve on the Residual Heat Removal Heat Exchanger Discharge Restricted HPSW Flow**.

2. Additional Operability Evaluations

a. Inspection Scope

The inspectors reviewed operability evaluations to assess the adequacy of the evaluations, the use and control of compensatory measures, compliance with the Technical Specifications, and the risk significance of the issues. The inspectors verified that the operability determinations were performed in accordance with Exelon administrative procedure LS-AA-105, "Operability Determinations." The inspectors used the Technical Specifications, Technical Requirements Manuals, the Updated Final Safety Analysis Report, and associated Design Basis Documents as references during these reviews. This inspection activity represented five samples. The issues reviewed included:

- Unit 3 control rod 14-47 scram inlet valve diaphragm leak on May 19, 2004
- E1 EDG air start check valve incomplete thread engagement on May 26, 2004

- Unit 3 reactor building ventilation system isolation damper air operator degraded rubber seat on May 26, 2004
- Unit 3 ‘A’ safety relief valve tail pipe temperature increase on May 28, 2004
- 2D RHR subsystem extent of condition review on June 17, 2004

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing (71111.19 - 7 Samples)

1. Unit 2 High Pressure Coolant Injection Turbine Failure

a. Inspection Scope

On May 14, 2004, during post-maintenance testing of the Unit 2 HPCI turbine, the main control room received a HPCI turbine bearing oil low pressure alarm. An equipment operator stationed in the Unit 2 HPCI room notified the control room that the HPCI governor bearing local oil pressure indicator indicated 0 psig, and the control room operators stopped the HPCI turbine. With the motor driven auxiliary oil pump in service, the equipment operator verified proper oil pressures to the other HPCI bearings. The equipment operator found the hand valve that supplies oil to the governor bearing to be mis-positioned. Subsequent investigation identified significant damage to the governor bearing and turbine rotor, requiring the bearing and the rotor to be replaced. The inspectors reviewed Exelon’s prompt investigation and immediate corrective actions in response to the event. This inspection activity represented one sample.

b. Findings

Introduction. Exelon’s failure to properly control the position of the HPCI turbine governor bearing oil supply valve during post-maintenance testing activities resulted in the loss of oil pressure to the bearing during operation. The resultant damage required replacement of the HPCI turbine rotor and approximately 170 hours of additional HPCI system unplanned unavailability. This issue constitutes a self-revealing finding of very low safety significance (Green) and a non-cited violation of Technical Specification (TS) 5.4, “Procedures.” The failure to adequately incorporate operating experience into the design, maintenance, and operation of the HPCI lubricating oil system was a contributing cause in the cross-cutting area of problem resolution.

Description. On May 10, 2004, the Unit 2 HPCI system was removed from service for a planned system outage. During the outage, maintenance was performed on the lubricating oil system which required manipulation of various valves within the system boundary. On May 13, 2004, at approximately 9:00 a.m., the lubricating oil system was restored to service using the motor drive auxiliary oil pump. The post-maintenance testing for this work activity established adequate oil pressure to HPCI governor bearing. On May 13, 2004, at approximately 12:00 p.m., the HPCI turbine was started and adequate oil pressure was verified to the governor bearing.

Between 3:00 p.m. on May 13, 2004 and 1:00 a.m. on May 14, 2004, several work activities were performed in the vicinity of the governor bearing oil supply valve. These included re-installation of insulation on adjacent steam piping, removal of a clearance tag from the valve handle, and removal of turbine predictive monitoring equipment. Exelon's interviews of individuals who performed these work activities did not identify any actions taken that would have bumped or jarred the governor bearing oil supply valve. Exelon's investigation concluded the governor bearing oil supply valve was bumped or jarred sometime during this time period.

At 1:00 a.m. on May 14, 2004, the HPCI turbine was started. Approximately one minute into the run, the control room received the Unit 2 HPCI turbine bearing oil low pressure alarm. Based on the equipment operator's report that the HPCI governor bearing local oil pressure indicator indicated 0 psig, the control room operators immediately stopped the HPCI turbine. It is estimated the turbine ran for approximately two minutes with no oil supply to the governor bearing. With the motor driven auxiliary oil pump still in service, the equipment operator identified the governor bearing oil supply valve out of position. The valve was repositioned and adequate oil pressure was restored to the governor bearing.

After reviewing oil and bearing temperature data and consulting with engineering personnel, operators made preparations to restart the HPCI turbine at 4:45 a.m. on May 14, 2004. This attempt was aborted prior to starting the turbine, due to an unrelated motor operated valve failure. Later in the day on May 14, 2004, after involving additional engineering and vendor support, a decision was made to inspect the turbine governor bearing and shaft. This inspection revealed extensive damage to the governor bearing and scoring of the turbine shaft. Replacement of the turbine rotor required approximately 170 hours of additional unplanned HPCI system unavailability.

Exelon's investigation into this event revealed several contributing factors related to inadequate use of operating experience and problem resolution. Historical issues pertaining to inadequacies of the use of a ball valve in this application were not acted on. A ball valve is inherently susceptible to slight movements in the valve handle position resulting in a sudden loss of oil pressure. A review of the work history for the governor bearing oil supply valve indicated the valve was replaced in 1993. The vendor manual requires a hole to be drilled in the valve ball to prevent inadvertent shutoff of the oil supply. Post-event inspection of the valve revealed a hole had not been drilled.

A contributing cause to the HPCI turbine failure was related to the problem identification and resolution cross-cutting area. Specifically, Exelon failed to adequately incorporate relevant operating experience into the design, maintenance, and operation of the HPCI lubricating oil system.

Analysis. This issue was more than minor because, if left uncorrected, the finding would become a more significant safety concern. The performance deficiency in this event was Exelon's failure to adequately control post-maintenance testing activities in that mis-positioning of the oil supply valve caused the failure of the Unit 2 HPCI turbine governor bearing due insufficient oil flow. Traditional enforcement does not apply because the issue did not have any safety consequence or potential for impacting the NRC's regulatory function and was not the result of any willful violation of NRC requirements or

Exelon's procedures. A Phase 1 SDP was performed and it was determined that the finding affected the mitigating systems cornerstone equipment reliability attribute. The failure of HPCI turbine bearing resulted in a loss of high pressure injection system safety function; therefore, a Phase 2 SDP was required. A regional risk analyst performed a risk assessment using the Peach Bottom Unit 2 & 3 SPAR model Change 3.02, created October 2003 that was revised to include NUREG/CR 5496 offsite power recovery probabilities. The HPCI system was assumed to fail to run after starting and no operator recovery was credited. The HPCI system was unavailable for approximately 170 hours for replacement of the HPCI turbine rotor and bearing as a result of this performance deficiency. The internal events conditional core damage probability (CCDP) was mid E-7 or Green based on the △core damage frequency (CDF). The licensee provided risk insights regarding the external events CCDP for this event and determined that the △CDF was in the low to mid E-7 range. Therefore, the combine risk of the internal and external events did not cross the green-white threshold. However, in accordance with the guidance of IMC 0609, Appendix H, Containment Integrity Significance Determination Process, Figure 4.1, LERF-based SDP, an assessment of the increase in risk due to the large early release frequency (LERF) Type A finding was required.

An internal events △LERF assessment was performed applying the IMC 0609, Appendix H, Table 5.2, Phase 2 Assessment Factors-Type A Findings at Full Power, LERF factors for a dry drywell and a station blackout (SBO). The Phase 2 △LERF result was mid E-7. A Phase 3 analysis was performed applying weighted LERF factors developed from an event tree that considered the full range of parameters regarding probability values for drywell flooding and depressurization. The licensee's external events risk assessment was a spatial evaluation that did not provide external events insights specific to dominant △LERF sequences; therefore, the external events risk contributors were not factored into the internal events △LERF assessment CCDP for this event. The Phase 3 △LERF result was high E-8 or a very low-significance, Green finding.

Enforcement. TS 5.4.1, "Administrative Controls - Procedures," requires that written procedures be established, implemented, and maintained covering safety-related activities listed in Regulatory Guide 1.33, Appendix A, November 1972. Regulatory Guide 1.33, Appendix A, Section I, "Procedures for Performing Maintenance," requires, in part, that maintenance which can affect the performance of safety-related equipment be performed in accordance with written procedures, documented instructions, or drawings appropriate to the circumstances. Contrary to the above, the inspectors determined Exelon's procedures for the Unit 2 HPCI turbine maintenance did not contain adequate controls to prevent the mis-positioning of the governor bearing oil supply valve during post-maintenance testing. As a result, oil flow to the bearing was interrupted with the turbine in service on May 14, 2004. Damage to the turbine bearing and rotor rendered the machine inoperable and required the bearing and rotor to be replaced. Because this finding is of very low safety significance and has been entered into the corrective action system (CR 221323), this violation is being treated as a non-cited violation, consistent with Section VI.A of the NRC Enforcement Policy: **NCV**

05000277/2004003-02, High Pressure Coolant Injection Turbine Failure During Post-Maintenance Testing Due to Mis-Positioned Oil Supply Valve.

2. Additional Post-Maintenance Testing

a. Inspection Scope

The inspectors observed portions of post-maintenance testing activities in the field and reviewed selected test data at the job site. The inspectors observed whether the tests were performed in accordance with the approved procedures and assessed the adequacy of the test methodology based on the scope of maintenance work performed. In addition, the inspectors assessed the test acceptance criteria to verify whether the test demonstrated that the tested components satisfied the applicable design and licensing bases and the Technical Specification requirements. The inspectors reviewed the recorded test data to evaluate whether the acceptance criteria was satisfied. This inspection activity represented six samples. The inspectors reviewed post-maintenance tests performed in conjunction with the following maintenance activities:

- E12 4KV under voltage relay functional test on April 15, 2004
- Unit 3 RCIC system outage on April 21, 2004
- Unit 2 average power range monitor (APRM) functional test on April 28, 2004
- Unit 2 condensate storage tank to HPCI suction check valve internal inspection on May 12, 2004
- Unit 2 HPCI turbine overspeed trip test on May 20, 2004
- E2 EDG overhaul on June 15, 2004

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22 - 6 Samples)

a. Inspection Scope

The inspectors reviewed and observed portions of surveillance tests, and compared test data with established acceptance criteria to verify the systems demonstrated the capability of performing the intended safety functions. The inspectors also verified that the systems and components maintained operational readiness, met applicable Technical Specification requirements, and were capable of performing the design basis functions. This inspection activity represented six samples. The observed or reviewed surveillance tests included:

- E2 diesel generator load reject on April 1, 2004
- Unit 3 ‘A’ RHR pump, valve, and flow on May 11, 2004
- Unit 2 HPCI pump, valve, and flow on May 13, 2004
- EDG main fuel oil tank sampling and analysis on May 25, 2004

- Unit 3 local power range monitor gain calibration on May 27, 2004
- 3B HPSW pump, valve, and flow on June 12, 2004

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications (71111.23 - 2 Samples)

a. Inspection Scope

The inspectors reviewed installed temporary plant modifications to verify that (1) the design bases, licensing bases, and performance capability of risk significant structures, systems, and components had not been degraded through this modification, and (2) that implementation of the modification did not place the plant in an unsafe condition. The inspectors verified the modified equipment alignment through control room instrumentation observations; UFSAR, drawing, procedure, and work order reviews; and plant walkdowns of accessible equipment. The inspectors reviewed a temporary plant modification for the lifted alarm leads on the Unit 3 HPSW discharge radiation monitor on May 18, 2004, and a temporary jumper hose installed to increase service water flow to the Unit 2 ‘A’ reactor feed pump turbine lube oil cooler on June 21, 2004. This inspection activity represented two samples.

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness [EP]

1EP6 Drill Evaluation (71114.06 - 1 Sample)

a. Inspection Scope

The inspectors observed an emergency planning drill on May 18, 2004, that simulated a security event followed by a reactor trip with fuel damage and offsite release. The inspectors focused on the performance of risk significant evolutions by site personnel in a simulated main control room and technical support center (TSC). These risk significant evolutions included emergency classification, NRC and offsite agency notifications, and coordination with the emergency operations facility (EOF) to issue the protective action recommendations (PARs). The inspectors also evaluated the emergency response organization’s recognition of abnormal conditions, command and control, communications, potential utilization of repair and field monitoring teams, and the overall implementation of the emergency plan procedures. The inspectors observed Exelon’s critique of personnel performance and verified that any weaknesses or deficiencies observed during the drill were discussed and evaluated. This inspection activity represented one sample.

b. <u>Findings</u>

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety [OS]

2OS1 Access Control to Radiologically Significant Areas (71121.01 - 1 Sample)

a. Inspection Scope

The inspector toured areas controlled as high radiation areas and reviewed the effectiveness of access controls to these areas. The inspector physically inspected and challenged three locked high radiation area access points to determine if access controls were sufficient to preclude unauthorized entry. This inspection activity represented one sample.

b. Findings

No findings of significance were identified.

Cornerstone: Public Radiation Safety [PS]

2PS2 Radioactive Material Processing and Transportation

1. Inspection Planning/In-Office Inspection (71122.02 - 1 Sample)

a. Inspection Scope

The inspector reviewed the solid waste system description in the Updated Final Safety Analysis Report (UFSAR) and recent radiological effluent release reports for information on the types and amounts of radioactive waste. (Audits are discussed in Section 4OA2 Problem Identification and Resolution.) This inspection activity represented one sample.

b. Findings

No findings of significance were identified.

2. System Walkdown (71122.02 - 1 Sample)

a. Inspection Scope

The inspector walked down accessible portions of the station's radioactive liquid and solid waste collection, processing, and storage systems and locations to determine if: systems and facilities were consistent with descriptions provided in the UFSAR; to evaluate their general material conditions; and to identify changes made to systems. Areas visually inspected were the Unit 2 and 3 condensate phase separator pump and tank rooms, Unit 2 and 3 condensate backwash receiving tank rooms, the waste surge and chemical tank rooms, waste sludge tank and pump room, and floor drain and waste collector pump and tank rooms. Visual inspection records for the A and B reactor water clean-up phase separator tank rooms were reviewed. Also, reviewed were the low level waste storage facility; the de-watering facility; the external storage areas; the moats for the condensate storage tanks; the refueling water storage tank; and the torus de-watering tank. This inspection activity represented one sample. The inspector reviewed the following matters:

- the status of any non-operational or abandoned radioactive waste process equipment and the adequacy of administrative and physical controls for those systems;
- changes made to radioactive waste processing systems and potential radiological impact including conduct of safety evaluations of the changes, as necessary;
- current processes for transferring radioactive waste resin and sludge to shipping containers and mixing and sampling of the waste, as appropriate;
- radioactive waste and material storage and handling practices;
- sources of radioactive waste at the station, processing (as appropriate) and handling of the waste; and
- the general condition of facilities and equipment.

The review was against criteria contained in the station's UFSAR, 10 CFR 20, 10 CFR 61, the Process Control Program (PCP), and applicable station procedures.

b. Findings

No findings of significance were identified.

3. Waste Characterization and Classification (71122.02 - 1 Sample)

a. Inspection Scope

The inspector reviewed the following matters:

- radio-chemical sample analysis results for radioactive waste streams;
- the development of scaling factors for difficult to detect and measure radionuclides including radionuclide concentration determination for irradiated hardware;
- methods and practices to detect changes in waste streams;
- classification and characterization of waste relative to 10 CFR 61.55 and 10 CFR 61.56;
- implementation of applicable NRC Branch Technical Positions (BTPs) on waste classification, concentration averaging, waste stream determination, and sampling frequency;
- current waste streams and their processing relative to descriptions contained in the UFSAR and the station's approved Process Control Program (PCP);
- current processes for transferring radioactive waste resin and sludge discharges into shipping/disposal containers to determine adequacy of sampling
- revisions of the PCP and the UFSAR to reflect changes (as appropriate).

The inspector also evaluated Exelon's methodology used to determine radionuclide content of irradiated metals.

The review was against criteria contained in 10 CFR 20, 10 CFR 61, 10 CFR 71, the UFSAR, the PCP, applicable NRC Branch Technical Positions, and licensee procedures. This inspection activity represented one sample.

b. Findings

No findings of significance were identified.

4. Shipment Preparation (71122.02 - Sample Not Completed)

a. Inspection Scope

The inspector reviewed the training and qualification documentation for personnel who had loaded and closed a Type B shipment of radioactive material (PW-03-040) on December 16, 2003. The inspector reviewed the completion of NRC Bulletin 79-19 training and training required by 49 CFR 172 Subpart H.

b. Findings

No findings of significance were identified.

5. Shipment Records and Documentation (71122.02 - Sample Not Completed)

a. Inspection Scope

The inspector selected and reviewed the records associated with four non-excepted shipments of radioactive material made since the previous inspection in this area (Shipment Nos. PW-03-040, PW-03-042, PW-03-019, PM-04-019). The following aspects of the radioactive waste, radioactive material packaging, and radioactive material shipping activities were reviewed.

- implementation of applicable shipping requirements including completion of waste manifests;
- implementation of the specifications in applicable Certificates of Compliance, as appropriate, for the approved shipping casks including limits on package contents;
- classification and characterization of waste relative to 10 CFR 61.55 and 61.56
- implementation of recent NRC and DOT shipping requirements rule changes;
- implementation of 10 CFR 20 Appendix G;
- implementation of specific radioactive material shipping requirements;
- packaging of shipments;
- labeling of shipping containers;
- placarding of transport vehicles;
- conduct of vehicle checks;
- provision of driver emergency instructions;
- completion of shipping paper/disposal manifest;
- evaluation of package against package performance standards, as appropriate;
- conformance with procedures for cask loading, closure and use requirements including consistency with cask vendor approved procedures;
- use of latest revision documents.

The review was against criteria contained in 10 CFR 20; 10 CFR 61; 10 CFR 71; applicable Department of Transportation requirements, as contained in 49 CFR 170-189 for the above areas; station procedures; applicable disposal facility licenses; and applicable Certificates of Compliance or vendor procedures for various shipping casks.

The inspector also reviewed the year 2003 Peach Bottom Combined Annual Radioactive Effluent Release Report, relative to types and quantities of radioactive waste shipped offsite and relative to changes to the PCP.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151 - 6 Samples)

a. Inspection Scope

The inspectors reviewed selected records at the station to assess the accuracy and completeness of the NRC Performance Indicator (PI) data. The records reviewed included Technical Specification limiting condition for operation logs, system surveillance tests, licensee event reports, action requests and condition reports. The information reviewed was compared against the criteria contained in Nuclear Energy Institute (NEI) 99-02, “Regulatory Assessment PI Guideline,” Revision 2. The inspectors verified that conditions met the NEI criteria, were recognized, identified, and accurately reported. This inspection activity represented six samples. The following specific indicators were reviewed for the previous four calendar quarters of reported data:

- Unit 2 and Unit 3 reactor coolant system (RCS) leakrate
- Unit 2 and Unit 3 RCS activity
- Unit 2 and Unit 3 residual heat removal (RHR) unavailability

b. Findings

No findings of significance were identified.

4OA2 Problem Identification and Resolution (71152)

As required by Inspection Procedure 71152, “Identification and Resolution of Problems,” and in order to help identify repetitive equipment failures or specific human performance issues for follow-up, the inspectors performed a daily screening of items entered into the licensee’s corrective action program. This review was accomplished by reviewing hard copies of each condition report, attending daily screening meetings, and accessing Exelon’s computerized database.

1. Semi-Annual Trend Review (71152 - 1 Sample)

a. Inspection Scope

The inspectors reviewed a list of over 1000 condition report (CR) items, categorized as Level 4D, that Exelon initiated from January 1, 2004, through June 30, 2004. The review was performed as part of the semi-annual Problem and Identification trend review of the Peach Bottom corrective action program. Level 4D CR’s are considered low level problems that do not require a formal investigation to determine the cause of the problem or corrective actions. Approximately 20 of the CRs were reviewed in detail to verify whether the full extent of the issues were adequately identified, and the appropriate level of evaluation and corrective actions were performed. The inspectors evaluated the CRs against the requirements of LS-AA-125, “Corrective Action Program (CAP) Procedure,” and 10 CFR 50, Appendix B, Criterion XVI, “Corrective Action”. The

CRs reviewed in detail were from the reactor building closed cooling water, reactor water clean up, and main steam systems. This sample represented 1 semi-annual PI&R trend review.

b. Findings and Observations

No findings of significance were identified.

Observation: The inspectors identified Exelon was not taking actions consistent with accepted industry practice for monitoring safety relief valve (SRV) performance. SRV performance is monitored by recording and trending temperatures on the relief valve discharge line. Each SRV discharge line is fitted with a thermocouple to detect valve operation and leakage. General Electric (GE) Services Information Letter (SIL) 196 dated September 30, 1976, provides recommendations for monitoring SRV discharge line thermocouple readings to detect pilot valve seat leakage. Operating experience has shown pilot valve seat leakage can lead to SRV self-actuation and loss of reactor coolant system pressure control. The SIL recommends the discharge line thermocouple be located to establish a baseline temperature in the range of 160F to 190F. The inspectors found the discharge line thermocouples on Unit 2 reading from a low of 244F to a high of 273F, and on Unit 3 from a low of 211F to a high of 258F.

Further, the GE SIL recommends establishing a baseline temperature for each SRV discharge thermocouple. The operating temperatures are to be compared against the baseline on a periodic basis with pre-established action levels to increase monitoring if the operating temperatures exceed the baseline temperature by 10F. If the operating temperature exceeds the baseline temperature by 30F, the GE SIL recommends repairing the valve at the earliest opportunity. The inspectors found that Exelon had not established baseline temperatures for the SRVs. Instead, Exelon had established a generic high temperature limit for each unit, 290F for Unit 2 and 260F for Unit 3. Based on the current plant conditions, the worst case SRV operating temperature could increase 49F before exceeding Exelon’s SRV monitoring limit. The inspectors also identified inconsistent performance monitoring by the assigned system engineer.

Exelon entered this issue into its corrective action program (CRs 168622, 176081, and 218774). Immediate corrective actions included changes to the control room operating logs establishing a baseline temperature for each SRV with upper band of 10F above baseline. Long term corrective actions have been initiated to relocate the SRV discharge line thermocouples to achieve baseline temperatures within the range recommended by the GE SIL.

This observation, and the problem identification and resolution cross cutting issue discussed in Section 1R19, are illustrative of weaknesses in Exelon’s processes for including relevant operating experience in the design, maintenance, and operation of safety significant plant systems.

2. Radioactive Waste Handling, Processing, Storage and Shipping Programs (71122.02 - 1 Sample)

a. Inspection Scope

The inspector reviewed assessments of the radioactive waste handling, processing, storage, and shipping programs including the Process Control Program (PCP). The inspector also reviewed selected corrective action documents written since the previous inspection. The following documents were reviewed:

- Nuclear Procurement Issues Audit No. TES-1-03, dated April 25, 2003, and associated audit report
- Nuclear Oversight Audit No. NOSA-PEA-04-04 (AR00214018)
- 2004 Radioactive Material Processing and Transportation Self-Assessment No. 212031
- Action/Issue Requests (221082, 220931, 220936)

The review was against criteria contained in 10 CFR 20 Appendix G, 10 CFR 71.101, and applicable station audit and surveillance procedures.

b. Findings

No findings of significance were identified.

3. Cross-References to PI&R Findings Documented Elsewhere

Section 1R15 describes a finding for inadequate design control. A previously identified problem involving degradation of high pressure service water valves was not corrected properly.

Section 1R19 describes a finding for failure to implement relevant industry operating experience in the design, maintenance, and operation of the HPCI lubricating oil system.

4OA3 Event Followup (71153)

1. (Closed) Licensee Event Report (LER) 05000277/2004001-00, Manual Scram Resulting from Low Condenser Vacuum Due to a Failed Feedwater Turbine Expansion Joint

On February 22, 2004, Peach Bottom Unit 2 was manually scrammed at approximately 3:10 p.m., as a result of decreasing main condenser vacuum. Prior to the event, at 2:24 p.m., an increase in the air inleakage into the condenser occurred. This prompted entry into the operational transient (OT) procedure for low condenser vacuum. Condenser vacuum was 27.1" Hg at the time the OT procedure was entered. A power reduction was performed to approximately 43% power with a resultant condenser vacuum of approximately 25.5" Hg. A briefing was conducted and the reactor was manually scrammed in accordance with the OT procedural direction since condenser vacuum was not restored to above the procedurally required 26.2" Hg value for the current plant condition. As a result of the manual scram, reactor water level decreased, as expected, to below the reactor water level-three (lo-level) set point resulting in Primary Containment Isolation System Group II and III isolations. The cause of the event was due to a leaking reactor feed pump turbine exhaust expansion joint. The expansion joint was repaired. There were no safety consequences as a result of this event. The resident inspectors did not identify any new issues in this LER review. Exelon documented the problem in the corrective action system (CR 203355). This LER is closed.

2. (Closed) LER 05000278/2004001-00, Loss of High Pressure Coolant Injection System Function As a Result of Inoperable Flow Controller

On March 17, 2004, at approximately 1235 hours, during the performance of a routine surveillance test for the HPCI system, operations personnel discovered that HPCI was inoperable. During performance of the surveillance test, the HPCI turbine could not achieve a speed above 1000 rpm and no significant discharge pressure was observed. Within two minutes of the initial turbine start, HPCI was tripped and the steam supply isolation valve was closed. The cause of the event is due to an inoperability of the HPCI system flow controller. The HPCI controller was discovered to not respond properly. The flow controller was replaced. HPCI was satisfactorily tested and returned to an operable status on March 19, 2004 by 0145 hours. Other flow related components on the HPCI system were evaluated and found to be in an acceptable condition. Other similar flow controllers (HPCI and RCIC) on Units 2 and 3 were evaluated for extent of condition concerns and determined to be operable. There were no actual safety consequences associated with this event. The resident inspectors did not identify any new issues in this LER review. Exelon documented the problem in the corrective action system (CR 209005). This LER is closed.

4OA5 Other

1. Operation of an Independent Spent Fuel Storage Installation (ISFSI) (60855)

a. Inspection Scope

The inspector observed selected spent fuel transfer operations for TN-68 Cask No. 22 conducted in accordance with independent spent fuel storage installation (ISFSI) procedure SF-220, “Spent Fuel Cask Loading and Transport Operations.” The licensee held a pre-job briefing with the work crew that morning where specific job responsibilities and industry lessons learned were reviewed. At the time of the inspection, TN-68-22 was loaded with spent fuel, sealed, and ready for transfer from the refuel floor in Unit 2 to the ISFSI pad. Final decontamination surveys and wipe downs were observed. Once TN-68-22 was relocated to the ISFSI pad, a tour of the ISFSI pad and enclosed area was conducted to ensure Tn-68 Tech Spec 4.2.1 criteria regarding cask spacing (center to center) was being maintained.

The inspector discussed with cognizant Exelon representatives the procedural controls in place that ensured only designated fuel assemblies were properly selected and loaded into TN-68 Casks. A review of the spent fuel assembly move sheets and verification records required by SF-300, “TN-68 Cask Spent Fuel Assemblies Storage Selection and Documentation Requirements,” was conducted. The inspector observed a video tape of final fuel configuration in TN-68 Casks Nos. 21 and 22 which indicated fuel assembly serial numbers. Fuel characteristics, including enrichments, burn-up, post irradiation cooling time, heat generation, and known structural defects, were reviewed and evaluated against the TN-68 Tech Spec 2.1.1 limits.

The inspector reviewed 10 CFR 72.48 safety evaluations generated since the last spent fuel transfer campaign in 2003. Procedure changes and incorporation of industry occurrences into the retraining program was also reviewed and discussed with cognizant Exelon representatives.

b. Findings

No findings of significance were identified.

2. TI 2515/156, Offsite Power

a. Inspection Scope

Temporary Instruction 2515/156, "Offsite Power." Phase I and Phase II of the inspection was completed during this inspection period. Appropriate documentation was provided to NRC management as required.

b. Findings

No findings of significance were identified.

4OA6 Meetings, Including Exit

1. Exit Meeting

On July 8, 2004, the resident inspectors presented the inspection results to Mr. Bob Braun and members of his staff, who acknowledged the findings. The inspectors confirmed that proprietary information was not provided or examined during the inspection.

2. Annual Assessment Meeting

On April 14, 2004, the NRC held a meeting with Exelon Generation Company, that was open for public observation, to discuss the results of the NRC's assessment of Exelon's performance at Peach Bottom Nuclear Power Station for the period January 1, 2003 through December 31, 2003. The handouts from the meeting are available electronically from the NRC's document system (ADAMS) under accession number ML040620014.

4OA7 Licensee-Identified Violations

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

- 10 CFR 55.25 requires in part, that the facility licensee notify the Commission within 30 days of discovery, that a licensed operator has been diagnosed with a permanent physical condition that adversely affects the performance of assigned operator job duties, so that the Commission can make a determination of the licensed operator's medical fitness. Contrary to this requirement on March 20, 2003, the facility licensee identified that a licensed operator underwent a medical procedure in December 1998 that should have been reported to the NRC. This issue was of very low safety significance because upon review of additional information provided by the facility licensee, the NRC physician determined that a restriction would not have been required because the licensed operator would have been able to perform licensed responsibilities without impairment. This failure to report medical information to the NRC impacted the regulatory process, and therefore, is classified at Severity Level IV.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Exelon Generation Company

B. Braun, Site Vice President
J. Grimes, Plant Manager
R. Artus, Requalification Training Instructor
C. Behrend, Plant Engineering Senior Manager
F. Cross, Radwaste and Environmental Manger
P. Davison, Engineering Director
E. Eiola, Operations Director
D. Foss, Senior Regulatory Engineer
C. Fritz, Training LTC 1-1
C. Hardee, Radiological Engineering Manager
K. Langdon, Work Management Director
R. Lubaszewski, Radwaste and Shipping Specialist
J. Mallon, Regulatory Assurance Manager
R. Norris, Radiation Protection Manager
G. Stathes, Maintenance Director
T. Van Wyen, Operations Training Manager

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

None

Opened and Closed

05000278/2004003-01	NCV	Design Changes Made to the High Pressure Service Water Motor Operated Valve on the Residual Heat Removal Heat Exchanger Discharge Restricted HPSW Flow (Section 1R15)
05000277/2004003-02	NCV	Unit 2 High Pressure Coolant Injection Turbine Failure During Post-Maintenance Testing Due to Mis-Positioned Oil Supply Valve (Section 1R19)

Closed

05000277/2004001-00	LER	Manual Scram Resulting from Low Condenser Vacuum Due to a Failed Feedwater Turbine Expansion Joint (Section 4OA3)
05000278/2004001-00	LER	Loss of High Pressure Coolant Injection System Function As a Result of Inoperable Flow Controller (Section 4OA3)

Discussed

None

LIST OF ACRONYMS

CCDP	conditional core damage probability
CDF	core damage frequency
CFR	Code of Federal Regulations
ECW	emergency cooling water
EDG	emergency diesel generator
ESW	emergency service water
HPCI	high pressure coolant injection
HPSW	high pressure service water
ISFSI	independent spent fuel storage installation
LERF	large early release frequency
LER	licensee event report
LOCA	loss-of-coolant accident
MOV	motor-operated valve
NCV	non-cited violation
NRC	Nuclear Regulatory Commission
OT	operational transient
PCP	process control program
RCIC	reactor core isolation cooling
RCS	reactor coolant system
RHR	residual heat removal
SDP	significance determination process
SRV	safety relief valve
SSC	structure, system, and component
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report