UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
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ARLINGTON, TEXAS 76011-8064

July 26, 2002

Joseph E. Venable
Vice President Operations
Waterford 3
Entergy Operations, Inc.
17265 River Road
Killona, Louisiana 70066-0751

SUBJECT: NRC INSPECTION REPORT 50-382/02-02

Dear Mr. Venable:

On June 29, 2002, the NRC completed an inspection at your Waterford Steam Electric Station, Unit 3. The enclosed report documents the inspection findings which were discussed on April 12, 24, and 30, June 20, and July 10, 2002, with you and other members of your staff.

This 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 consisted of selected examination of procedures and representative records, observations of activities, and interviews with personnel.

Based on the results of this inspection, the NRC has identified issues that were evaluated under the risk significance determination process as having very low safety significance (Green). The NRC has also determined that violations are associated with these issues. These violations are being treated as noncited violations (NCVs), consistent with Section VI.A of the Enforcement Policy. These NCVs are described in the subject inspection report. If you contest the violation or significance of these NCVs, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001, with copies to the Regional Administrator, U.S. Nuclear Regulatory Commission, Region IV, 611 Ryan Plaza Drive, Suite 400, Arlington, Texas 76011; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the Waterford Steam Electric Station, Unit 3, facility.

The NRC has increased security requirements at Waterford 3 in response to terrorist acts on September 11, 2001. Although the NRC is not aware of any specific threat against nuclear facilities, the NRC issued an Order and several threat advisories to commercial power reactors to strengthen licensees' capabilities and readiness to respond to a potential attack. The NRC continues to monitor overall security controls and will issue temporary instructions in the near future to verify by inspection the licensee's compliance with the Order and current security regulations.

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

Should you have any questions concerning this inspection, we will be pleased to discuss them with you.

Sincerely,

/RA/

William B. Jones, Chief
Project Branch E
Division of Reactor Projects

Docket: 50-382
License: NPF-38

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NRC Inspection Report
50-382/02-02

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ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Docket:	50-382
License:	NPF-38
Report:	50-382/02-02
Licensee:	Entergy Operations, Inc.
Facility:	Waterford Steam Electric Station, Unit 3
Location:	Hwy. 18 Killona, Louisiana
Dates:	March 31 through June 29, 2002
Inspectors:	T. R. Farnholtz, Senior Resident Inspector G. F. Larkin, Resident Inspector L. T. Ricketson, P.E., Senior Health Physicist W. C. Sifre, Reactor Inspector P. J. Elkmann, Emergency Preparedness Inspector G. A. Pick, Senior Physical Security Inspector J. S. Dodson, Project Engineer G. M. Vasquez, Project Engineer R. P. Mullikin, Senior Reactor Inspector
Accompanying Personnel:	I. Barnes, Reactor Consultant T. L. Klug, Physical Security Inspector
Approved By:	W. B. Jones, Chief, Project Branch E
Attachment:	Supplemental Information

SUMMARY OF FINDINGS

Waterford Steam Electric Station, Unit 3
NRC Inspection Report 50-382/02-02

IR05000382-02-02; on 03/31/02-06/29/02; Entergy Operations, Inc.; Waterford Steam Electric Station, Unit 3; Integrated Resident & Regional Report; Maint. Risk Assessments & Emergent Work Eval.; Access Control to Significant Radiological Areas; Ident. & Resolution of Problems.

The inspection was conducted by resident inspectors, a senior health physicist inspector, an emergency preparedness inspector, a senior physical security inspector, a senior reactor inspector, a reactor inspector, and two project engineers. The inspection identified four Green issues. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using IMC 0609, "Significance Determination Process" (SDP). The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described at its Reactor Oversight Process website at http://www.nrc.gov/NRR/OVERSIGHT/index.html. Findings for which the SDP does not apply are indicated by "No Color" or by the severity level of the applicable violation.

Cornerstone: Mitigating Systems

- Green. The inspectors identified a violation of Technical Specification 6.8.1 for the failure to maintain proper foreign material exclusion controls in accordance with Procedure UNT 007-059 while working to correct piping misalignment at Check Valve MS-402A, on the emergency feedwater AB main steam supply line. This violation is being treated as a noncited violation consistent with Section VI.A.1 of the NRC Enforcement Policy and is in the licensee's corrective action program as Condition Report 2002-0628.

  The safety significance of this violation was more than minor because it could be reasonably viewed as a precursor to a more significant event due to the potential for foreign material to enter the main steam line, affecting the ability of the Emergency Feedwater AB turbine to operate as required. This issue was determined to be of very low safety significance (Green) because there was no foreign material found in the main steam piping system during the final system closure inspection (Section 1R13).

Cornerstone: Occupational Radiation Safety

- Green. The licensee failed to survey and control a high radiation area correctly. When items containing radioactive material were placed into a trash holding area on the -4-foot elevation of containment on April 7, 2002, the licensee failed to perform a radiation survey, in violation of 10 CFR 20.1501(a), to evaluate the additional hazard and to adjust the placement of the rope barricade and warning signs (posting). Consequently, radiation dose rates at the rope barricade and posting exceeded the dose rates allowed by Technical Specification 6.12 by a factor of two, demonstrating that the rope barricade and posting did not encompass and control the entire high radiation area. This violation is being treated as a noncited violation consistent with Section VI.A.1 of the NRC Enforcement Policy. This item is documented in the licensee's corrective action program as Condition Report 2002-00726.

The finding had a credible impact on safety because workers could have unknowingly worked in the high radiation area outside the barricades and postings. The occurrence involved the potential for individual worker unplanned, unintended dose resulting from actions or conditions contrary to licensee procedures, Technical Specifications, or NRC regulations, which could have been significantly greater if people had worked in the area. Using the Occupational Radiation Safety Significance Determination Process, the inspector determined the finding had only very low safety significance (Green) because it is not an ALARA finding, an overexposure, a situation involving a substantial potential for overexposure, or an item compromising the ability to assess dose (Section 2OS1).

Cornerstone: Identification and Resolution of Problems

- Green. The inspectors identified a violation of 10 CFR Part 50, Appendix B, Criterion XVI, Corrective Action, for the failure to correct the cause of voiding in the low-pressure safety injection system and to take effective corrective action to preclude repetition of this condition, which had existed for several months prior to the March 23 through April 17, 2002, refueling outage (RF11). The licensee failed to correct the root cause of this condition during the scheduled refueling outage. A total of seven unplanned entries into Technical Specification 3.5.2 Action (a) were made as a result of voids large enough to render Low-Pressure Safety Injection System Train A or B inoperable during the period April 18 through June 14, 2002. This violation is being treated as a noncited violation consistent with Section VI.A.1 of the NRC Enforcement Policy and is in the licensee's corrective action program as Condition Report 2002-0818.

  This violation was determined to have greater than minor safety significance because it affected the operability, availability, reliability, and function of the low-pressure safety injection system. This issue was determined to be of very low safety significance (Green) because only one train of the low-pressure safety injection system was affected at any one time and the Technical Specification allowed outage time was not exceeded (Section 4OA2).

- Green. The licensee failed to enter the action statement of Technical Specification 3.7.3 and exceeded the allowed outage time of 72 hours to restore Auxiliary Component Cooling Water Pump B to an operable status. This pump was inoperable for approximately 8 days with a degraded outboard pump bearing. This violation is being treated as a noncited violation consistent with Section VI.A.1 of the NRC Enforcement Policy and is in the licensee's corrective action program as Condition Report 2001-1399.

  This violation was determined to have greater than minor safety significance because it affected the operability, availability, reliability, and function of Auxiliary Component Cooling Water Pump B. The issue was determined to be of very low safety significance (Green) after an NRC senior reactor analyst performed a Phase 3 Significance Determination Process analysis. The analysis included the inoperable period of the pump and system utilization during the winter period (Section 4OA2).

Report Details

Summary of Plant Status: The plant was shutdown and in a scheduled refueling outage (RF11) at the beginning of this inspection period. On April 16, 2002, operators commenced a reactor startup to perform low power physics testing. The main turbine generator was placed online on April 17 and the refueling outage ended on that day. Power was increased and reached approximately 100 percent on April 21 and remained at that level for the remainder of the inspection period.

1 REACTOR SAFETY

Initiating Events, Mitigating Systems, Barrier Integrity (R)

1R01 Adverse Weather Protection (71111.01)

a. Inspection Scope

The inspectors conducted three inspections which included a walkdown of three areas inside and outside the plant to verify that the licensee has made hurricane season preparations and that the following are protected from adverse weather:

- Electrical distribution switchyard, including the auxiliary and startup transformers
- Dry cooling tower (ultimate heat sink)
- Main turbine generator

The inspectors also reviewed Operating Procedure OP-901-521, “Severe Weather and Flooding,” Revision 3; Procedure W6.103, “Emergency Preparedness Hurricane Policy and Preparation/Response Guidelines, Revision 4; and the Updated Final Safety Analysis Report, Section 3.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (71111.04)

a. Inspection Scope

The inspectors reviewed and observed the following three partial system equipment alignments during this inspection period:

- Spent Fuel Pool Cooling and Purification: On April 11, 2002, the inspectors completed a partial walkdown of the critical mechanical and electrical components in spent fuel pool cooling and Purification Trains A and B. This walkdown began as spent fuel was initially moved from the reactor vessel to the spent fuel pool. A final walkdown was conducted after completion of all Refueling Outage 11 fuel movement. The review included a review of the Updated Final Safety Analysis Report and Operations Procedure OP-002-006, “Fuel Pool Cooling and Purification,” Revision 15.

- Component Cooling Water Train AB: On May 9, 2002, the inspectors completed a review and partial system walkdown of Component Cooling Water System Train AB, which was aligned and operating on Train A while Component Cooling Water Pump A was out of service for scheduled maintenance. The review included the Updated Final Safety Analysis Report and Operations Procedure OP-903-003, “Component Cooling Water System,” Revision 13.

- Emergency Feedwater Pump B: On June 5, 2002, the inspectors walked down the Emergency Feedwater Pump B main flow path valve lineup and electrical breaker alignment. This pump was lined up in a standby condition while Emergency Feedwater Pump A was tagged out for planned maintenance. The walkdown was conducted using Operations Procedure OP-009-003, “Emergency Feedwater,” Revision 11.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

a. Inspection Scope

The inspectors conducted six tours during this inspection period to assess the material condition of the active and manual fire detection and suppression systems and to determine if combustible materials were appropriately controlled in the following areas:

- Reactor containment building -4-foot, +21-foot, and +46-foot elevations on April 12, 2002

- Turbine generator building +15-foot elevation and the transformer yard on April 30, 2002

- Diesel-driven and motor-driven fire pump rooms and associated equipment on May 2, 2002

- High-pressure safety injection, low-pressure safety injection (LPSI), and Containment Spray Trains A and B compartments on June 11, 2002

- Condensate pump pit area and turbine generator on June 12, 2002

- Emergency Diesel Generator Rooms A and B and Component Cooling Water Pump Room B on June 13, 2002

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures (71111.06)

a. Inspection Scope

The inspectors conducted two reviews of the licensee’s internal and external flood protection measures to ensure that adequate precautions had been taken to mitigate any flood risks. The inspectors reviewed Procedure OP-901-521, “Severe Weather and Flooding,” Revision 3, for external event and internal flooding; Flood Analysis Calculation MN(Q)-3-5, “Flooding Analysis Outside Containment,” Revision 3; Dry Cooling Tower Calculation EC-M97-029, “Dry Cooling Tower Area Drain Sump Pump Minimum Capacity,” Revision 0; Temporary System Alteration TA-01-009, ER-W3-2001-1232-000, “Temporary Alteration to Leave Vent Rigs Installed on SI-133A and SI-1402A”; Updated Final Safety Analysis Report, Chapter 3; Condition Reports 2001-0793, -0819, and -0827 and 2002-0122, -0354, and -1049 to ensure that no safety significant flood protection structures, systems, or components had overdue corrective actions; and applicable controlled drawings in support of this inspection. The inspectors toured the following internal areas to ensure that flood protection boundaries were adequately closed or sealed:

- Dry cooling tower
- Lower level of the fuel handling building

The inspectors also toured the following external areas to ensure that flood protection boundaries were adequately closed or sealed:

- Lower level of the auxiliary building
- Lower level of the turbine building

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance (71111.07B)

.1 Test Methodology for Safety-Related Heat Exchangers

a. Inspection Scope

The inspectors reviewed the licensee's test methodology for the component cooling water system heat exchangers, emergency diesel generator jacket water heat exchangers, and the containment cooling units. In addition, the inspectors reviewed test data for the heat exchangers and design and vendor-supplied information to ensure that the heat exchangers were performing within their design basis. The inspectors also reviewed the heat exchanger inspection and test results. Specifically, the inspectors reviewed the test packages to verify proper extrapolation of test conditions to design conditions, appropriate use of test instrumentation, and appropriate accounting for instrument inaccuracies. This was also to verify that the licensee appropriately trended these inspection and test results, assessed the causes of the trends, and took necessary actions for any step changes in these trends.

b. Findings

No findings of significance were identified.

.2 Verification of Conditions and Operations Consistent with Design Bases

a. Inspection Scope

For the selected heat exchangers, the inspectors considered whether the licensee-established heat sink and heat exchanger condition, operation, and test criteria were consistent with the design assumptions. Specifically, the inspectors reviewed the applicable calculations to ensure that the thermal performance test acceptance criteria for the heat exchangers were being applied consistently throughout the calculations. The inspectors also considered whether the appropriate acceptance values for fouling and tube plugging for the component cooling water heat exchanger remained consistent with the values used in the design-basis calculations. The inspectors also considered whether the parameters measured during the thermal performance and flow balance of the component cooling water system were consistent with those assumed in the design bases.

b. Findings

No findings of significance were identified.

.3 Identification and Resolution of Problems

a. Inspection Scope

The inspectors examined the corrective action program for problems associated with heat sink components over the past 2 years. The inspectors selected a sample of seven condition reports for review, which are identified in the attachment to this report.

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection Activities (71111.08)

The licensee's inservice inspection program plan was currently in the second 40-month period of the second 10-year interval. The current refueling outage is the last outage of the second 40-month period. The station inservice inspection program was committed to the 1989 edition of the Section XI code, with no addenda. The licensee, however, had committed to the 1995 code, 1996 addenda, for the performance demonstration initiative required by 10 CFR 50.55a. The licensee had also committed to Revision 5 of the Electric Power Research Institute guidelines for the examinations conducted under their steam generator management program.

.1 Performance of Nondestructive Examination Activities

a. Inspection Scope

The inspector observed the following examinations which were performed by licensee nondestructive examination personnel:

System	Component/Weld Identification	Examination Method
Safety Injection System	Weld 08-008	Magnetic Particle, Ultrasonic
Reactor Coolant Pump 1A	Weld 08-014	Ultrasonic
Main Steam	Weld MS-124A-U	Magnetic Particle
Safety Injection System	Weld SIRR-0175A	Magnetic Particle
Reactor Vessel Head Stud	01-S-19	Magnetic Particle, Ultrasonic
Reactor Vessel Head Stud	01-S-21	Magnetic Particle, Ultrasonic
Reactor Vessel Head Stud	01-S-22	Magnetic Particle, Ultrasonic
Reactor Vessel Head Stud	01-S-26	Magnetic Particle, Ultrasonic
Reactor Vessel Head Stud	01-S-28	Magnetic Particle, Ultrasonic
Reactor Vessel Head Stud	01-S-30	Magnetic Particle, Ultrasonic
Reactor Vessel Head Stud	01-S-34	Magnetic Particle, Ultrasonic
Reactor Vessel Head Stud	01-S-36	Magnetic Particle, Ultrasonic

During observation of the examinations, the inspectors determined that the examinations were conducted in accordance with approved procedures, properly calibrated equipment was used, expended consumables met shelf-life requirements, and the results were correctly documented in the draft examination report. Upon completion of the examinations, the inspector reviewed a sample of "Certificates of Qualification" to verify that the examiners conducting the examinations were certified in the appropriate technique to the appropriate level. Finally, the inspector reviewed the final (record) examination reports to determine that identified examination indications were dispositioned in accordance with the ASME code requirements and properly documented.

b. Findings

No findings of significance were identified.

.2 Steam Generator Condition Management Activities

a. Inspection Scope

The inspector reviewed all and observed selected elements of the licensee's processes for determining and maintaining the condition of the steam generators. These processes included:

- Eddy current inspection of steam generator tubes
- Removing steam generator tubes from service
- Secondary side inspection
- Cleaning of the secondary side
- Recovery and/or disposition of any loose parts on the secondary side
- Primary to secondary leak identification and analysis
- Control of condensate, feedwater, and steam generator chemistry

The review was conducted by examination of the licensee's programmatic procedures, assessment of the licensee's evaluation for deviating from the Electric Power Research Institute guidance documents, review and comparison of previous outage summary reports to the analysis of data during the current outage, and validation of various data for the current steam generator degradation assessment.

The inspectors considered whether the licensee had performed at least the minimum allowable eddy current tube inspections required by the Technical Specifications. Followup review was performed to validate that tubes meeting the limiting and administrative criteria were plugged using the specified methodology.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11)

a. Inspection Scope

On May 6, 2002, the inspectors observed licensed operators conducting requalification activities in the control room simulator. The simulator scenario involved a tornado that created a loss of off-site power to the plant with a subsequent failure of Emergency Diesel Generator Trains A and B to supply power to the emergency buses. The scenario ended when the licensed and nonlicensed operators restored power to an emergency bus. This scenario was part of the licensed operators' regularly scheduled requalification cycle. The inspectors also observed the postexercise critique to determine if all the critical training objectives were met.

b. Findings

No findings of significance were identified.

1R12 Maintenance Rule Implementation (71111.12)

a. Inspection Scope

The inspectors reviewed the Maintenance Rule data for the following six systems to determine if the Maintenance Rule scope and unavailability criteria for these systems had been appropriate:

- Shutdown Cooling System: On April 10, 2002, the inspectors completed a review of the shutdown cooling system to determine if the requirements of the Maintenance Rule had been applied appropriately. The inspectors reviewed the Maintenance Rule scoping document, the condition reports, and the Maintenance Rule functional failure determination checklists for the last 36 months. Some problems were experienced with this system during Refueling Outage 11.

- 4.16 kV Electrical Distribution: On May 20, 2002, the inspectors completed a Maintenance Rule review of the 4.16 kV electrical distribution system. The inspectors reviewed the Maintenance Rule function list, the unavailability criteria, and the reliability criteria. In addition, the inspectors reviewed the condition reports and Maintenance Rule functional failure determination checklists for the last 18 months.

- Boric Acid Makeup: On May 20, 2002, the inspectors completed a Maintenance Rule review of the boric acid makeup system. The inspectors reviewed the Maintenance Rule scoping document, which included the function list, the unavailability criteria, and the reliability criteria. In addition, the inspectors reviewed the applicable condition reports and Maintenance Rule functional failure determination checklists for the last 18 months.

- Broad Range Toxic Gas Monitors: On May 24, 2002, the inspectors completed a review of the broad range toxic gas monitor system to determine if the requirements of the Maintenance Rule had been applied appropriately. The inspectors reviewed the Maintenance Rule scoping document, condition reports, and Maintenance Rule functional failure determination checklists for the last 18 months. This system was included in the Maintenance Rule as (a)(1) due to cumulative unavailability hours.

- Feedwater Controls: During the week of June 24, 2002, the inspectors completed a review of the Maintenance Rule application for the feedwater control system. The functional failure criteria for this system was established at the plant level. The inspectors reviewed the condition reports and maintenance preventable functional failure checklists for the past 18 months.

- Core Protection Calculators: During the week of June 24, 2002, the inspectors completed a review of the core protection calculators with regard to the Maintenance Rule. This system exceeded the established Maintenance Rule performance criteria and was placed in (a)(1) status. Reliability problems continue with this system and the licensee has included it on their top ten equipment list. The inspectors reviewed the condition reports and functional failure checklists for the past 18 months.

b. Findings

No findings of significance were identified.

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

.1 4 kV Essential Switchgear 3A3-S Maintenance Outage

a. Inspection Scope

From April 1-3, 2002, the licensee performed maintenance on 4 kV Essential Switchgear 3A3-S. The inspectors reviewed the scope of the work outage and the required troubleshooting methods, that the existing plant configuration was suitable for the outage scope, and that the correct equipment alignment was restored after the switchgear outage. In addition, the inspectors reviewed Condition Report 2002-0722 and Maintenance Action Items 426260, 426810, and 426811. The inspectors also interviewed responsible outage managers, schedulers, planners, and maintenance electricians to verify appropriate consideration was given to the risks associated with the maintenance activities.

b. Findings

No findings of significance were identified

.2 Control Element Assemblies

a. Inspection Scope

On April 26, 2002, the inspectors performed a review of Maintenance Action Items 435769 and 435957 and Condition Report 2002-0849. The two work packages detailed maintenance to be conducted on Shutdown Group B, Subgroup 3, and Regulating Group 2, Subgroup 17. The inspectors reviewed the packages to determine if appropriate consideration had been given to risk assessment.

b. Findings

No findings of significance were identified.

.3 Emergency Diesel Generator A Sequencer Lockout and Undervoltage Override Circuitry

a. Inspection Scope

On May 14, 2002, the licensee performed an 18-month surveillance test on the Emergency Diesel Generator A sequencer lockout and undervoltage override circuitry. During the surveillance test, the sequencer is inoperable. The licensee's risk model considered this plant condition as analogous to losing Emergency Diesel Generator A and the same train of off-site power. However, operator action could bring any needed safety equipment on line during the sequencer testing that would mitigate an ongoing event. The inspectors reviewed the work scope, risk contingency plan, Technical Specification/Technical Requirements Manual clarification sheet, Maintenance Action Item 433992, and Surveillance Procedure ME-003-302, "EDG Undervoltage Override and Sequential Lockout Logic Circuit Testing," Revision 0. In addition, the inspectors attended the prejob briefings and interviewed the applicable operations and electrical maintenance managers and maintenance electricians to verify appropriate risk was considered for the required maintenance activities.

b. Findings

No findings of significance were identified

.4 Emergency Feedwater Pump AB Turbine Steam Supply Valve MS-401A from Steam Generator 1

a. Inspection Scope

On May 30, 2002, the inspectors completed an assessment of work controls used to replace Emergency Feedwater Pump AB Turbine Steam Supply Valve MS-401A. The inspectors reviewed the work scope, attended prejob briefings, and interviewed the applicable planners and schedulers, maintenance managers, and mechanics to verify appropriate risk was considered for the required maintenance activities.

b. Findings

The inspectors identified a violation of Technical Specification 6.8.1 for the failure to follow Administrative Procedure UNT-007-059, "Foreign Material Exclusion," Revision 1. The finding was determined to affect the mitigating system cornerstone and to be of very low safety significance (Green) using the significance determination process.

On April 1, 2002, the inspectors toured the +46-foot level of the reactor auxiliary building to site check the work area at Emergency Feedwater Pump AB Turbine Steam Supply Valve MS-401A, a valve recently installed in the piping system. While in the work zone, the inspectors noticed that the pipe flanges on both sides of Check Valve MS-402A were disassembled. The piping downstream of Check Valve MS-402A was cold sprung and left a gap between Check Valve MS-402A and the downstream pipe flange. Neither Check Valve MS-402A or the downstream pipe flange (steam supply to the Emergency

Feedwater Pump AB Turbine) were covered or posted as a foreign material exclusion zone, nor were there mechanics in the work zone to prevent foreign material entry into the open piping. Procedure UNT-007-059, step 5.4.4.2, requires all unattended openings to be covered, capped, etc., using an approved foreign material exclusion device, or the zone should be posted. The plant was in Mode 6.

This issue had greater than minor safety significance using the reactor safety significance determination process because foreign material could enter the piping system. Foreign material in that portion of the main steam system had the potential of subsequently entering the Emergency Feedwater Pump AB turbine during a turbine run. The Emergency Feedwater Pump AB turbine is an important mitigating component in preventing core damage for various accident scenarios. The inspectors found that the issue had very low safety significance because no foreign material was found in the piping system during the subsequent licensee inspection prior to reassembling the valve flanges.

The inspectors determined that the failure to follow Administrative Procedure UNT-007-059, "Foreign Material Exclusion," Revision 1, constituted a violation of Technical Specification 6.8.1. This is being treated as a noncited violation, consistent with Section VI.A of the NRC's Enforcement Policy and is in the licensee's corrective action program as Condition Report 2002-0628 (NCV 50-382/02002-01).

.5 Emergency Feedwater Pump A

a. Inspection Scope

On June 19, 2002, the inspectors completed a review of scheduled work performed on Emergency Feedwater Pump A. Specifically, the pump was tagged out to perform maintenance on a feeder breaker alarm relay. The inspectors reviewed the work controls associated with removing and reinstalling the components during online power operations and the equipment out-of-service risk model used to quantify the equipment outage risk to plant operations. The work was performed using Procedure ME-007-036, "G.E. Auxiliary Relay's 12HFA51A, 12HFA51B and 12HFA151B7F," Revision 8.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors reviewed the following six operability evaluations:

- Low Temperature Overpressure Protection Relief Valve Bolting Material: On May 3, 2002, the inspectors completed a review of the operability evaluation associated with Condition Report 2002-0858, which described a condition in which the inlet flange studs for the low temperature overpressure protection Relief Valve B and the discharge flange bolts for both Relief Valves A and B had been overtorqued. This was due to the wrong bolting material being used at these locations.

- Backup Pressurizer Heaters: On May 20, 2002, the inspectors completed a review of the operability evaluation associated with Condition Report 2002-0942, which described a condition in which the backup pressurizer heater circuit breaker coordination was not established appropriately. The operability evaluation detailed the concern and the ability of the breakers to provide primary containment penetration conductor overcurrent protection.

- Closure Mechanism of the Main Feedwater Isolation Valves: On May 20, 2002, the inspectors completed a review of the operability evaluation associated with Condition Report 2002-0953, which described a condition in which the closure mechanism for the main feedwater isolation valves did not provide a constant closing force on the valve. This condition could result in the valves drifting open under certain circumstances. The inspectors reviewed the operability evaluation to determine if this condition was examined for appropriate situations.

- Emergency Diesel Generator A Lube Oil High Temperature Alarm Switch: On June 4, 2002, the inspectors reviewed the operability evaluation associated with Condition Report 2002-1023, which described a condition in which the Emergency Diesel Generator A lube oil high temperature switch setpoint was found 8.7°F high out of tolerance. The operability evaluation was reviewed to determine if it considered all appropriate aspects for the stated condition.

- Scaffold Interfering with Component Cooling Water Line: On June 25, 2002, the inspectors reviewed Condition Report 2002-1093 concerning a condition in which temporary scaffolding was constructed in the vicinity of a component cooling water line. The scaffolding was found to be touching the line, which caused minor damage to the outside of the piping. The associated operability evaluation was reviewed to determine if it was complete and addressed all appropriate concerns.

- Emergency Feedwater Pump Turbine Steam Supply Line Heat Tracing: On June 25, 2002, the inspectors reviewed the operability evaluation associated with Condition Report 2002-1112. The described condition involved a steam supply line temperature control panel trouble alarm, which required the operators to take compensatory actions to ensure continued operability of the emergency feedwater system steam-driven pump. The operability evaluation detailed the compensatory actions and the reasoning for continued operability of the pump.

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications (71111.17)

a. Inspection Scope

The inspectors evaluated the change in the reactor vessel head insulation from reflective stainless steel to fiberglass blanket. The licensee documented this modification in Engineering Request ER-W3-1999-0198-004, “Modify Insulation on the Reactor Head.” As described in Section 4OA5, the licensee could not remove the center section of the reflective stainless steel insulation. Consequently, the licensee modified the engineering request. The inspectors reviewed Revision 1 to Engineering Request ER-W3-1999-0198-004-01.

The inspectors used the following additional documents to complete this inspection:

- Calculation MN(Q)-6-18, “Thermal Insulation Material Inside Containment,” dated November 2, 1999

- Calculation MN(Q)-6-35, “Safety Injection System Sump and Screen,” dated July 1, 1998

- Balance of Plant Criteria, letter dated April 16, 1971

- PCI-WT3-RPV-HL-01, “Waterford 3 Reactor Pressure Vessel Top Head Heat Loss Analysis With the NUKON Insulation System,” dated March 14, 2002

- Vendor Manual 457002668, “NUKON Insulation”

- SPEER [Substitute Part Equivalency Evaluation Report] 9701667, “Engineering Evaluation for NUKON Insulation - Reactor Vessel Closure Head,” dated June 8, 1997

- Procurement Specification DES-M-002, “Nuclear Blanket-type Thermal Insulation With Stainless Steel Jacketing For Piping and Components,” Revision 3, dated March 3, 1997

- Information Notice 90-07, “New Information Regarding Insulation Material Performance and Debris Blockage of PWR Containment Sumps,” dated January 30, 1990

- Maintenance Action Item 425995, “Installation of Reactor Vessel Head Blanket Insulation,” dated November 8, 2001

- Drawing WFU3-RPV-6002, “Reactor Pressure Vessel Top Head Insulation Layout”

The inspectors evaluated the following characteristics: (1) material compatibility with the reactor vessel head, (2) environmental qualification for the containment conditions, and

(3) evaluation of containment sump performance. The inspectors interviewed engineers and insulation installers and reviewed the work instructions contained in the Vendor Manual, the engineering request, and the work package.

b. Findings

No findings of significance were identified.

1R19 Postmaintenance Testing (71111.19)

a. Inspection Scope

The inspectors reviewed postmaintenance testing activities conducted on the following four components:

- Main Steam Valve MS-116B, Atmospheric Dump Valve B: The inspectors completed an evaluation of the postmaintenance testing completed on MS-116B. On April 11, 2002, MS-116B stroked faster than the minimum stroke time allowed in the licensee's inservice test program. The stroke time is used to detect valve abnormalities and take corrective action before the valve reaches a high failure probability. The inspectors reviewed Condition Report 2002-0742, Maintenance Action Item 402467, and OP-903-120, "Containment and Miscellaneous Systems Quarterly IST Valve Tests," Revision 5.

- Steam Generator 1 Feedwater Isolation Valve: On April 17, 2002, the inspectors completed a review of the work package developed to perform scheduled maintenance on the Steam Generator 1 feedwater isolation valve. The inspectors reviewed Maintenance Action Items 434411, 427081, and 431036 and Condition Report 2002-0624 to determine if the specified postmaintenance test was appropriate for the work performed.

- Component Cooling Water Pump A: On May 10, 2002, the inspectors completed an evaluation of the postmaintenance testing conducted on Component Cooling Water Pump A to verify operability. The test was conducted in accordance with Operations Procedure OP-903-050, "Component Cooling Water and Auxiliary Component Cooling Water Pump and Operability Test," Revision 16.

- Chill Water Expansion Tank AB Level Control Valve: On June 24, 2002, the inspectors completed a review of the work and postmaintenance testing performed on the Chill Water Expansion Tank AB level control valve. This component and associated equipment required troubleshooting to identify the scope of the maintenance required. Postmaintenance testing was performed in accordance with Operations Procedure OP-903-119, "Secondary Auxiliaries Quarterly IST Valve Tests," Revision 6.

b. Findings

No findings of significance were identified.

1R20 Refueling and Outage Activities (71111.20)

a. Inspection Scope

From the beginning of this inspection period until the end of Refueling Outage 11 on April 17, 2002, the inspectors monitored the licensee's control of outage activities, including the following:

- Observed the second scheduled draindown of the reactor coolant system to midloop conditions to ensure the requirements of Generic Letter 88-17 were met

- Reviewed reactor coolant system level instrumentation used during midloop operations to determine if it was installed and functioned as expected

- Reviewed plant electrical lineups to determine if the designated protected train was maintained

- Monitored shutdown cooling system operating parameters to establish whether they were maintained within the required range

- Reviewed reactor coolant system inventory control and reactivity control measures

- Observed portions of fuel movement activities in both the fuel handling building and the containment building

- Verified that spent fuel pool and associated support equipment performed as required to maintain temperature and level within specifications

- Verified that containment closure could be accomplished within required times during various portions of the outage

In addition, the inspectors observed several risk significant plant operations, including reactor vessel reassembly and plant startup performed in accordance with Operations Procedure OP-010-003, "Plant Startup," Revision 1, and Procedure NE-002030, "Initial Criticality," Revision 6. The inspectors also observed portions of low power physics testing conducted using Procedure NE-002-003, "Post-Refueling Startup Testing," Revision 10.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors observed or reviewed the following six surveillance activities:

- Emergency Diesel Generator A: From March 29 to April 4, 2002, the inspectors observed portions of the setup and performance of the emergency diesel generator integrated test. This test was performed in accordance with Surveillance Procedure OP-903-015, “Train A Integrated Emergency Diesel Generator/Engineering Safety Features Test,” Revision 7. The surveillance procedure provided instructions to test the Emergency Diesel Generator A sequencer relays and the response of the relays to a safety injection actuation signal with offsite power available and with a loss of offsite power. The inspectors assessed whether the licensee considered the plant risks associated with the effects of the test and that the test data met the surveillance procedure requirements and acceptance criteria. The inspectors also reviewed Condition Reports 2002-0657, -0673, and -0674 that were associated with this test.

- Safety-Related Battery B Discharge Test: On April 5, 2002, the inspectors observed a scheduled surveillance activity to conduct a discharge test of Safety-Related Battery B. The test was conducted in accordance with Procedure ME-003-230, “Surveillance Procedure Battery Service Test,” Revision 13. The inspectors also reviewed the completed test data sheets to determine if all acceptance criteria had been met.

- Emergency Diesel Generator B: From April 5-8, 2002, the inspectors observed portions of the setup and performance of the emergency diesel generator integrated test. This test was performed in accordance with Surveillance Procedure OP-903-016, “Train B Integrated Emergency Diesel Generator/Engineering Safety Features Test,” Revision 8. The surveillance procedure provided instructions to test the Emergency Diesel Generator B sequencer relays and the response of the relays to a safety injection actuation signal with offsite power available and with a loss of offsite power. The inspectors considered whether the licensee considered the plant risks associated with the effects of the test, and that the test data met the surveillance procedure requirements and acceptance criteria. The inspectors also reviewed Condition Reports 2002-0715 and -0729 that were associated with this test.

- Emergency Feedwater Pump A/B Turbine Overspeed Trip Test: On April 8, 2002, the inspectors observed a scheduled surveillance test and reviewed the results of the uncoupled emergency feedwater turbine mechanical overspeed trip test. The test was performed in accordance with Surveillance Procedure MM-003-016, “Emergency Feedwater Pump Turbine Mechanical Overspeed Trip Test and Calibration,” Revision 6, and Maintenance Action

Item 429667. The procedure provided instructions to operational check, inspect, and adjust the emergency feedwater pump turbine mechanical overspeed trip mechanism.

- Reactor Coolant System Leakage Rate: On June 4, 2002, the inspectors completed a review of data sheets for the reactor coolant system leakage test conducted since January 2001. This surveillance test was performed in accordance with Operations Procedure OP-903-024, "Reactor Coolant System Water Inventory Balance," Revision 11.

- Dry Cooling Tower Fan Logic Test: On June 19, 2002, the inspectors completed a review of the test results of a Dry Cooling Tower Channel A fan logic test. The work package included a graphical representation of the test results. The test was conducted in accordance with Procedure MI-005-565, "Dry Cooling Tower Fan Logic Test Train A or B," Revision 3.

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope

The inspectors conducted a review of the following two temporary plant modifications to determine if they were installed in accordance with Procedure UNT-005-004, "Temporary Alteration Control," Revision 15:

- Temporary Alteration 01-009: Temporary alteration to leave vent rigs installed on SI-133A and -1402A. This temporary modification was installed to facilitate venting of the LPSI Train A due to an ongoing nitrogen intrusion condition

- Temporary Alteration 02-001: Temporary setpoint change for Turbine Bearing 11Y vibration module. This temporary modification was installed as a result of a step increase in the vibration level of Main Turbine Bearing 11

b. Findings

No findings of significance were identified.

Emergency Preparedness

1EP4 Emergency Action Level and Emergency Plan Changes (71114.04)

a. Inspection Scope

The inspectors performed in-office reviews of the following emergency plan and emergency plan implementing procedures against previous revisions and 10 CFR 50.54(q) to determine if the revisions decreased the effectiveness of the emergency plan:

- Waterford 3 Steam Electric Station Emergency Plan, Revision 27, approved December 18, 2001;
- Waterford 3 Steam Electric Station Emergency Plan, Change 27-1, approved February 28, 2002;
- Waterford 3 Steam Electric Station Emergency Plan, Change 27-2, approved March 9, 2002;
- Procedure EP-001-001, “Recognition and Classification of Emergency Conditions,” Revision 20, approved February 28, 2002.

b. Findings

No findings of significance were identified.

2 RADIATION SAFETY

Occupational Radiation Safety

2OS1 Access Control to Radiological Significant Areas (71121.01)

a. Inspection Scope

The inspectors interviewed radiation workers and radiation protection personnel involved in high dose rate and high exposure jobs during Refueling Outage 11 operations to collect information about the licensee’s exposure controls. The inspector also conducted plant walkdowns within the controlled access area and conducted independent radiation surveys of selected work areas. The following items were reviewed and compared with regulatory requirements:

- Radiation protection program procedures
- Area posting and other controls for airborne radioactivity areas, radiation areas, high radiation areas, and very high radiation areas

- Radiation work permits (RWPs) and radiological surveys involving airborne radioactivity areas, high radiation areas, and electronic dosimeter alarm setpoints

- Access controls, surveys, and RWPs for high dose work areas from Refueling Outage 11 (RWP 2002-1508, “Inspect/Rework RCP Motors”; RWP 2002-1510, “Install/Remove Steam Generator Nozzle Dams”; RWP 2002-1618, “Remove/Replace Insulation in Locked High Radiation Areas”; and RWP 2002-1716, “Diving in Contaminated Water Near Highly Radioactive Components”)

- Dosimetry placement when work involved a significant dose gradient

- Locked high radiation area key control program

- Summary of condition reports written since September 2001, related to access controls and high radiation area incidents (with in-depth review of Condition Reports 2001-1095, 2001-1106, and 2002-498)

- Briefing for RWP 2002-1716, “Diving in Contaminated Water Near Highly Radioactive Components”

- Conduct of work with the potential for high radiation dose

- Controls involved with the storage of highly radioactive items in the spent fuel pool (Reactor Engineering Procedure UNT-007-001, “Control of Miscellaneous Material in the Spent Fuel Pool,” Revision 3)

- Self-assessments (QS-2002-W3-014, “Pre-Job Briefing for Containment Entry”; WLO-2002-006, “Access Control to Radiologically Significant Areas”; and WLO-2002-26, “Reactor Containment Building Entry at 100% Power”)

b. Findings

The inspector identified a violation of very low safety significance (Green) because a high radiation area was not correctly surveyed and controlled.

On April 8, 2002, the inspector performed confirmatory measurements around the boundaries of high radiation areas inside the reactor containment building. (As defined by 10 CFR 20.1003, a high radiation area is an area in which radiation levels could result in an individual receiving a dose equivalent in excess of 0.1 rem (100 millirems) in 1 hour at 30 centimeters from the radiation source or from any surface that the radiation penetrates.) At the boundary of a trash storage area on the -4-foot elevation, the inspector measured a radiation dose rate of 200 millirems per hour. This measurement was confirmed by a licensee representative. This dose rate exceeded the limit of 100 millirems per hour and meant that the entire high radiation area was not encompassed by the rope barricades and warning signs (posting). The inspector determined through interviews and reviews of the radwaste logbook and radiation survey records that two vacuum cleaners containing radioactive material were placed into the trash storage area on April 7, 2002. However, the radiation protection technician providing coverage of the job failed to measure or survey the dose rates at the existing area boundary and make necessary adjustments to the barricades and posting. Consequently, a high radiation area existed outside the high radiation area posting and barricade.

In determining the significance of the finding, the inspector concluded that the finding had a credible impact on safety because workers could have unknowingly worked in the high radiation area outside the barricades and postings. The occurrence involved the potential for individual worker unplanned, unintended dose resulting from actions or conditions contrary to licensee procedures, Technical Specifications, or NRC regulations, which could have been significantly greater if people had worked in the area. Using the Occupational Radiation Safety Significance Determination Process, the inspector determined the finding had only very low safety significance because it is not an ALARA finding, an overexposure, a situation involving a substantial potential for overexposure, or an item compromising the ability to assess dose.

10 CFR 20.1501 requires that each licensee make or cause to be made surveys that may be necessary for the licensee to comply with the regulations in Part 20 and that are reasonable under the circumstances to evaluate the extent of radiation levels, concentrations or quantities of radioactive materials, and the potential radiological hazards that could be present. A survey is defined by 10 CFR 20.1003 as an evaluation of the radiological conditions and potential hazards incident to the production, use, transfer, release, disposal, or presence of radioactive material or other sources of radiation. In this issue, the licensee failed to conduct a survey and comply with 10 CFR 20.1601(c) and the licensee's "alternative method" for controlling access to high radiation areas, Technical Specification 6.12, which requires that each radiation area in which the intensity of radiation is greater than 100 millirems per hour be barricaded and conspicuously posted. This violation is being treated as a noncited violation consistent with Section VI.A.1 of the NRC Enforcement Policy. This item is documented in the licensee's corrective action program as Condition Report 2002-00726 (NCV 50-382/0202-02).

4 OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

a. Inspection Scope

The inspectors reviewed initiating events cornerstone performance indicator data for the following three performance indicators:

- Performance indicator data for Safety System Unavailability (SSU) - Emergency AC Power System for the first quarter of 2002 on April 19, 2002

- Performance indicator data for SSU - High-Pressure Injection System for the first quarter of 2002 on May 3, 2002

- Performance indicator data for SSU - Heat Removal System for the first quarter of 2002 on May 28, 2002

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

.1 Occupational Exposure Control Effectiveness

a. Inspection Scope

The inspectors reviewed corrective action program records involving locked high radiation areas (as defined in Technical Specification 6.12.2), very high radiation areas (as defined in 10 CFR 20.1003), and unplanned exposure occurrences (as defined in NEI 99-02) for the past 12 months (through the fourth quarter of 2001) to confirm that these occurrences were properly recorded as performance indicators. Controlled access area entries with exposures greater than 100 millirems within the past 12 months were reviewed, and selected examples were examined to determine whether they were within the dose projections of the governing RWPs. Whole body counts or dose estimates were reviewed if the radiation worker received a committed effective dose equivalent of more than 100 millirems.

b. Findings

No findings of significance were identified.

.2 Radiological Effluent Technical Specification/Off-site Dose Calculation Manual Radiological Effluent Occurrences

a. Inspection Scope

The inspectors reviewed radiological effluent release program corrective action records, licensee event reports, and annual effluent release reports documented during the past four quarters (through the fourth quarter of 2001) to determine if any doses resulting from effluent releases exceeded the performance indicator thresholds (as defined in NEI 99-02).

b. Findings

No findings of significance were identified.

.3 Voiding in the LPSI System

a. Inspection Scope

On June 28, 2002, the inspectors completed a review of the licensee's actions regarding voiding in the LPSI system. These are long-term issues that have contributed to equipment failures along with operations, engineering, and radiological challenges. The inspectors conducted interviews with responsible engineers, operators, and managers and reviewed relevant documents and drawings.

b. Findings

The inspectors identified a violation of 10 CFR Part 50, Appendix B, Criterion XVI, Corrective Action, for the failure to correct and preclude repetition of a condition causing voiding in LPSI Train A. The finding was determined to be of very low safety significance (Green) using the significance determination process.

The NRC staff recognizes the licensee's efforts to address and resolve the long-term conditions which have resulted in void formations within the emergency core cooling systems and, in particular, the LPSI system. Significant licensee management involvement has been noted with regard to addressing the void formation. These efforts date back to 1996. However, these efforts have not realized effective results as demonstrated by having to declare the LPSI Train A inoperable multiple times following the corrective actions taken to address this issue during the last refueling outage. During the past refueling outage, a check valve was replaced to correct the condition which contributed to the void formations and actual operational events during the past operating cycle. These challenges included voiding within a LPSI pump during a surveillance activity and lifting of a relief valve in the LPSI system during high-pressure safety injection system operation. In addition, the operator actions that have been implemented to address the voids have resulted in substantive operator workarounds that have been ongoing for a substantial period of time.

The inspectors conducted a comprehensive review of void formation in the LPSI system and in the shutdown cooling water system from the mid-1990s through the end of the inspection period.

The licensee concluded at least as early as December 1996 that nitrogen from the safety injection tanks was entering the LPSI system. Each train of LPSI system has two piping connections to the emergency core cooling header in containment, which contains nitrogen saturated water from the safety injection tanks. Nitrogen saturated water from the emergency core cooling header had migrated into the LPSI system where the nitrogen comes out of solution, forming voids at the high points of the system. These voids result in challenges to operations and engineering personnel to monitor and remove these voids to maintain the low-pressure safety injection system in an operable status.

From November 1996 through February 1997, several events were documented concerning pressure spikes and void formation in the LPSI system. The pressure spikes were caused by the sudden collapse of voids upon starting the LPSI pump, resulting in water hammer events. The licensee determined that the water hammer events caused only minor pipe support damage and no loss of system integrity or function.

To mitigate gas voiding consequences, the licensee began to: (1) periodically perform an ultrasonic test to verify that the arc length of the nitrogen pocket did not exceed preset limits (Condition Report 1997-0200 and Special Test Procedure 01156545); (2) check for nitrogen pockets following any valve stroke or pump surveillance test; (3) increase the refueling water storage pool level to increase the pressure exerted on any residual nitrogen pockets that formed between system venting; and (4) install high point vents, completed during Refueling Outage 8, between the flow control valves and the inboard containment isolation valves.

From 1997 through 1999, three additional condition reports (1997-0200 and 1998-0024 and -0069) documented gas voiding in LPSI Train A. Between January and November 2000, one condition report (2000-0965) was written. This condition report documented that venting operations were unable to reliably determine that gas bubbles were vented from the system piping due to the physical plant configuration and the collection method that was used. Additionally, the vented gas was not quantified or documented to allow for trending and tracking in the licensee's monitoring program. The next condition report (CR 2001-0430) documenting gas voiding was written 8 months later in April 2001.

On October 30, 2000, the licensee wrote Engineering Request ER-W3-00-0877-00-00 to document that Check Valve SI-142A exhibited chronic problems of disk misalignment, excessive clearances, and seat leakage. The licensee decided not to repair the valve due to lack of vendor support and the required tools to perform repairs. The valve was reassembled using the existing parts and placed back in service. The failure to perform effective corrective actions to correct this condition was identified as a noncited violation of 10 CFR Part 50, Appendix B, Criterion XVI, Corrective Action, with very low safety significance (Green) and documented in NRC Inspection Report 50-382/01-07.

In April 2001, Condition Report 2001-0430 documented that the Safety Injection Tank 2B level was decreasing approximately 1 percent per day. From July 10 to September 26, 2001, the LPSI Train A header was pressurized greater than 200 psig from safety injection tank water leaking into the discharge header. Technical Specification surveillance-required venting was ineffective in reducing system pressure to ambient during this time period. No condition reports documenting this problem were found.

On September 23 and December 20, 2001, LPSI Train A Header Thermal Relief Valve SI-132A, set to lift at 650 psi, lifted off its seat due to leakage past Check Valve SI-142A. No condition reports documenting this problem were found.

As documented in Section 1R22 of NRC Inspection Report 50-382/01-07, on November 30, 2001, LPSI Pump A became vapor bound (Condition Report 2001-1295). The licensee's investigation revealed that the likely cause was seat leakage past Check Valve SI-142A allowing nitrogen saturated water from Safety Injection Tank 2B to migrate into the LPSI Train A discharge line. No gas sample was obtained to determine the composition.

From November 30, 2001, to January 1, 2002, 14 additional condition reports documented voiding issues in the LPSI system piping.

On February 26, 2002, the licensee was performing the reactor auxiliary building fluid system leak test using High-Pressure Safety Injection Pump B. This test resulted in the inadvertent pressurization of the LPSI Train A discharge header and the probable lifting of LPSI Pump A Header Thermal Relief Valve SI-132A (Condition Report 2002-0339). The cause of this event was identified as leakage past Check Valve SI-142A. The licensee evaluated the LPSI system piping and structural integrity and concluded that the system was not adversely affected.

During Refueling Outage 11, the licensee replaced Safety Injection System Check Valve SI-142A and reinstalled the normally closed manual bypass valve around Check Valve SI-142A. The manual bypass valve was torqued to its maximum value in the closed position following installation. This action was taken to correct the identified condition where leakage past the check valve from the safety injection tanks resulted in voiding in the LPSI system. Prior to plant startup, the shutdown cooling water portion of LPSI System Trains A and B were realigned for the standby injection mode. The systems were monitored for the formation of voids during plant startup and plant operation. This was accomplished by ultrasonic testing and venting of the high points on a more frequent interval than required by Technical Specification surveillance requirements.

On April 18 (the day after Refueling Outage 11 ended), a void was identified in LPSI System Train B, which required Train B to be declared inoperable, and an unplanned entry into Technical Specification 3.5.2 Action (a) was made. Numerous small voids were subsequently identified during the first several weeks of operation after the end of Refueling Outage 11 in both trains, but did not require any unplanned entries into the Technical Specification statement. These voids were vented and no additional system operability concerns were identified during that time. On May 14, 2002, a void was identified in LPSI System Train A, which required this train to be declared inoperable, and an unplanned entry into the Technical Specification statement was made. The void was vented and the system declared operable. Since that time, five additional voids of sufficient size were identified in Train A that required unplanned entries into the Technical Specification action statement (June 1, 3, 5, 13, and 14). Many smaller voids, not requiring the system to be declared inoperable, were also identified during this time. No additional voids have been identified in Train B large enough for the train to be declared inoperable.

Since the end of Refueling Outage 11, the licensee developed several theories as to the cause of these voids. These included continued leakage past the newly installed Safety Injection Check Valve SI-142A, leakage past the manual bypass valve around Check Valve SI-142A, and gases coming out of solution from the reactor coolant system water contained in the LPSI system after being realigned to the injection mode from the shutdown cooling mode of operation. The inspectors considered it possible that the root cause could be a combination of these or other factors.

This finding was determined to have greater than minor safety significance because it had a credible impact on safety and did affect the operability, availability, reliability, and function of the LPSI system. This issue was determined to be of very low safety significance because only one train of the LPSI system was affected at any one time and the Technical Specification allowed outage time was not exceeded.

10 CFR Part 50, Appendix B, Criterion XVI, Corrective Action, states in part that measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances are promptly identified and corrected. In the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition.

The inspectors determined that the failure to correct the voiding in the Train A LPSI system and to take effective corrective action to preclude repetition of this condition constituted a violation of Criterion XVI. This issue is being treated as a noncited violation, consistent with Section VI.A of the NRC's Enforcement Policy and is in the licensee's corrective action program as Condition Report 2002-0818 (NCV 50-382/02002-03).

.4 Failure of Auxiliary Component Cooling Water Pump B Outboard Bearing

a. Inspection Scope

The Auxiliary Component Cooling Water Pump B outboard journal bearing partially failed during a weekly chemical mixing of Wet Cooling Tower Basin Train B on December 23, 2001, and completely failed on December 30 during the next weekly chemical mixing of Wet Cooling Tower Basin Train B. The inspectors reviewed Condition Report 2001-1399 and the root cause analysis associated with this event. In addition, the inspectors interviewed responsible engineers, licensing personnel, and maintenance workers to assess the licensee's problem identification and resolution methods and the results associated with the failed Auxiliary Component Cooling Water Pump B outboard journal bearing.

b. Findings

A violation of Technical Specification 3.7.3 was identified for exceeding the allowed 72 hours to restore Auxiliary Component Cooling Water Pump B to an operable status. This pump was inoperable for approximately 8 days with a wiped outboard pump bearing caused by the licensee's failure to prevent foreign material from entering the pump bearing oil system. The finding was determined to affect the mitigating system cornerstone and to be of very low safety significance (Green) using Phase 3 of the Significance Determination Process.

On December 30, 2001, the Auxiliary Component Cooling Water Pump B outboard journal bearing wiped completely. The plant entered the action statement for Technical Specification 3.7.3, a 72-hour shut down limiting condition for operation. The pump was returned to service within 72 hours. On February 15, 2002, the licensee determined that the plant should have entered Technical Specification 3.7.3 on December 23, 2001. On December 23, the outboard journal bearing temperature rose from approximately 115°F to 175°F in 8 minutes, then decreased to approximately 110°F (normal) and remained at that level until the pump was secured. Total pump run time was approximately 30 minutes. The licensee believed the increased bearing temperature represented an oil flow blockage to the journal bearing that created a minor bearing wipe. During the previous run on December 11, the pump operated for approximately 11.5 hours with normal journal bearing temperatures with no indications of problems.

The root cause determination report and the licensee event report stated that "The pump's inoperability was caused by the failure of the pump's outboard bearing, which resulted from the failure to exclude foreign material from the lubricant during maintenance or oil addition." The licensee additionally considered the following mechanisms for contributing to the failure of the journal bearing: incorrect lubricant, pump shaft/bearing misalignment, a bent shaft, excessive bearing loading, and bearing instability. The inspectors talked with several people who were on site during the bearing disassembly. An engineer and a maintenance supervisor reported foreign material under the bearing cap near the wiped bearing. This foreign material was later lost before tests or detailed observations were completed on the material. The mechanics who disassembled the bearing did not see any foreign material inside the bearing housing.

The licensee's root cause determination report stated that, "One small piece of foreign material was found inside the lower portion of the outboard bearing housing. This material was most likely a piece of the gasket material that was dislodged when the top portion of the bearing housing was removed. The appearance and location of this material did not indicate that it had initiated the bearing failure. No other evidence of foreign material was detected. If the foreign material that blocked the inlet port was nonmetallic, it would have most likely been broken up when it passed through the bearing." Vendor analysis of the wiped bearing did find foreign material in the bearing and the licensee did not find impurities in the oil drained from the bearing sump.

The Auxiliary Component Cooling Water Pump B bearing assembly is a Kingsbury Type "CH" with an integral housing containing an oil circulator, journal bearing, and thrust bearing. The inspectors observed that the licensee did not inspect the thrust bearing, oil circulator, and oil sump for a degraded material condition that could reduce oil flow to the bearing working surfaces, verify these areas free of foreign material, or drain all the oil from the bearing housing sump for analysis and for additional possible foreign material. The foreign material that was reported found inside the bearing housing was lost before any analyses or pictures of the foreign material were made to determine how the material may have entered the system, how the material may have interrupted oil flow to the journal bearing, or whether the material present during the bearing's failure was responsible for the bearing's failure.

Based on Auxiliary Component Cooling Water Pump B performance since January 2002, the inspectors considered this pump to be operable.

Engineering personnel effectively missed the partial bearing wipe on December 23, 2001. Engineering guidelines and expectations did not ensure that the plant monitoring computer data base was reviewed for adverse conditions on a frequent enough basis to prevent the plant from exceeding a limiting condition for operation.

This finding was determined to have greater than minor safety significance because it had an actual impact on safety and did affect the operability, availability, reliability, and function of Auxiliary Component Cooling Water Pump B. The issue was determined to be of very low safety significance (Green) based on the result of an NRC senior reactor analyst significance determination process Phase 3 analysis. The analysis included the 8 days from the pump run and the system utilization during the winter period.

The inspectors determined that the failure to enter the action statement of Technical Specification 3.7.3 on December 23, 2001, and exceeding the 72-hour maximum allowed outage time constituted a violation. This issue is being treated as a noncited violation consistent with Section VI.A of the NRC's Enforcement Policy and is in the licensee's corrective action program as Condition Report 2001-1399 (NCV 50-382/02002-04).

4OA3 Event Followup (71153)

.1 (Closed) Violation (VIO) 50-382/9901-01: Inadequate Audit Independence

During an NRC inspection conducted on January 25-29 and February 8-12, 1999, one violation of NRC requirements was identified. The inspector determined that Licensee Audits SA-98-025.1 and SA-98-036.1 dated September 16, 1998, which reviewed the access authorization and fitness-for-duty programs respectively, were conducted by individuals who were not independent of the program management being audited. The licensee evaluated the violation under Condition Report CR-WF-1999-0143. As a result of the evaluation, the licensee included in their Master Audit Plan the requirement for personnel conducting audits of the access authorization and fitness for-duty programs to be functionally independent of program management and implementation.

The inspectors conducted an in-office review of Condition Report CR-WF-1999-0143 and the Master Audit Plan for the Fitness-For-Duty and Access Authorization programs and concluded that the licensee completed the appropriate corrective actions.

.2 (Closed) Licensee Event Report 50-382/02-003-00: Inoperable Auxiliary Component Cooling Water Pump due to Lack of Lubrication

The inspectors reviewed this event during this inspection period. The inspectors documented the results in Section 4OA2 of this report. The Region IV Senior Reactor Analyst performed a Significance Determination Process Phase 3 screening of this issue and concluded that this issue is a finding of very low safety significance.

4OA5 Other

Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles (NRC Bulletin 2001-01 and Temporary Instruction 2515/145)

This Temporary Instruction provided guidelines to verify compliance with licensee commitments to NRC Bulletin 2001-01, "Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles." Further, this evaluation confirmed licensee compliance with applicable regulatory requirements (i.e., 10 CFR Part 50, Appendix A; 10 CFR Part 50, Appendix B; and 10 CFR 50.55a). As identified in the Temporary Instruction, Waterford 3 falls within the category of moderate-susceptible plants. Consequently, the inspectors used the criteria for evaluating moderate-susceptible plants to conduct this inspection.

a. Inspection Scope

The inspectors conducted this performance-based evaluation and assessment to ensure that the NRC had an independent review of the condition of the reactor vessel head and vessel head penetrations. This assessment included evaluating the effectiveness of the licensee examinations of the vessel head penetrations. The inspectors: (1) reviewed the examination criteria used by the individuals performing the examinations, (2) interviewed personnel who performed the examinations, (3) evaluated the training conducted in preparation of the examinations, (4) assessed adequacy of the examination plan and procedures, (5) observed in-process examinations, (6) evaluated the quality and resolution of the examination equipment, (7) reviewed the completed records, (8) reviewed licensee documented deficiencies in their corrective action process, and (9) assessed the overall effectiveness of the process used to perform the bare metal effective visual examination.

The inspectors used the following documents to conduct this inspection:

- Generic Letter 88-05, “Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components In PWR Plants,” dated March 17, 1988

- Information Notice 90-10, “Primary Water Stress Corrosion Cracking (PWSCC) of Inconel 600,” dated February 23, 1990

- Information Notice 2001-05, “Through-wall Circumferential Cracking of Reactor Pressure Vessel Head Control Rod Drive Mechanism Penetration Nozzles at Oconee Nuclear Station, Unit 3,” dated April 30, 2001 (ML011160588)

- MRP-44, Part 2, EPRI TR-1001491, “PWR Materials Reliability Program Interim Alloy 600 Safety Assessments for US PWR Plants, Part 2: Reactor Vessel Top Head Penetrations,” dated May 2001

- NRC Bulletin 2001-01, “Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles,” dated August 30, 2001 (ML012080284)

- 30-Day Response to NRC Bulletin 2001-01 For Waterford 3; “Circumferential Cracking of VHP (Vessel Head Penetration) Nozzles,” dated September 4, 2001 (ML012530227)

- MRP-48, EPRI TR-1006284, “PWR Materials Reliability Program Response to NRC Bulletin 2001-01,” dated August 2001

- Supplement to 30-Day Response to NRC Bulletin 2001-01 For Waterford 3; “Circumferential Cracking of VHP (Vessel Head Penetration) Nozzles,” dated November 8, 2001

- NRC Bulletin 2001-01, “Circumferential Cracking of Reactor Pressure Vessel Head Penetration Nozzles,” Responses For Waterford Steam Electric Station, Unit 3 (TAC No. MB2674), dated November 23, 2001 (ML013270344)

- Waterford 3 Reactor Vessel Head Penetration Inspection Criteria, dated January 22, 2002

- Visual Examination for Leakage of Reactor Head Penetrations on Top of Head, dated August 10, 2001

- Procedure QAP-410, “Reactor Vessel Head VT Examination (Alloy 600),” Revision 0, dated February 21, 2002

- Procedure NDE-2.12, “Certification of Visual Testing Personnel,” Revision 0, dated March 1, 2001

- Procedure UNT-007-027, “Control of Boric Acid Corrosion on the Reactor Coolant System,” Revision 3, dated September 29, 2001

- Maintenance Action Item 425996, Perform Visual inspection of Vessel Head Penetration Nozzles, completed March 31 and April 1, 2002

- Drawing SK-C-X-58, “Reactor Vessel Head Inspection Layout”

- Drawing 1564-7404, “Closure Head Insulation Layout A-1"

- Information Notice 2002-11, “Recent Experience With Degradation of Reactor Pressure Vessel Head,” dated March 12, 2002

- NRC Bulletin 2002-01, “Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity,” dated March 18, 2002

- 15-Day Response to NRC Bulletin 2002-01, “Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity,” dated April 1, 2002

- Waterford 3 Relief Request - “Proposed Alternative to ASME Examination Requirements for Repairs Performed on Reactor Vessel Head Penetrations,” dated February 28, 2002

- Waterford 3 Relief Request - “Use of Mechanical Nozzle Seal Assemblies,” dated March 1, 2002

- Waterford 3 Relief Request - “Use of Electrical Discharge Machining (EDM),” dated March 14, 2002

- As Low As Reasonably Achievable (ALARA) Prejob Planning Package

- Condition Reports 2002-0566, 2002-0636, 2002-0645, and 2002-0659

The inspectors observed 50 percent of the in-process vessel head penetration examinations performed using a boroscope and a small sample of the in-process examinations performed using a robot with a mounted camera. The licensee used the boroscope because they could not remove the permanent reflective stainless steel insulation surrounding 20 of the 101 vessel head penetrations. In addition, the inspectors inspected the reactor vessel head and independently reviewed the video tapes of the vessel head penetration examinations.

b. Findings

The inspectors identified no findings of significance. The inspectors concluded that the licensee performed a good, effective bare metal examination of the vessel head penetrations. The clarity and resolution of the examination equipment combined with the training, qualification, and procedures ensured that the examiners could detect small boron deposits. The inspectors have provided the following details of the inspection as required by Temporary Instruction 2515/145.

.1 Examination

The licensee examination team consisted of a VT-2 qualified examiner, who documented the examination and operated the equipment, and a responsible engineer, who would evaluate along with the examiner any indications. Additionally, the licensee had a second team, which consisted of a VT-2 qualified examiner and another engineer to independently assess, remotely, the condition of the vessel head penetrations. These two teams coordinated the examination of the reactor vessel head penetration nozzles, including indexing the nozzle locations. The inspectors concluded that the index process used during the examinations ensured that the licensee had inspected all nozzles 360° around the nozzle circumference.

The inspectors interviewed the personnel who performed the VT-2 examinations of the reactor vessel head. The examiners used a boroscope in difficult to reach locations and a robot for the remainder of the vessel head penetrations. The inspectors verified that the VT-2 qualified examiners had current qualification records. During interviews the inspectors confirmed that the examiners and engineers knew how to identify indications of leakage. The inspectors determined that the personnel involved in the vessel head penetration examinations had been associated with Inconel 600 concerns and the material reliability project. These individuals had seen numerous photographs detailing leakage from vessel head penetrations. The licensee provided a training session that included: (1) the examination criterion and (2) photographs of vessel head penetrations with leakage and previous existing leakage stains.

The inspectors verified that the licensee had an adequate, approved procedure that described the examination criterion. The inspectors noted that Procedure QAP-410 referenced attached photographs as indicating typical penetration leakage were of very poor quality; however, the inspectors concluded this deficiency was not significant since the color photographs provided during the training session were of excellent quality. The licensee had initiated Condition Report 2002-0659 to document this deficiency and corrected the procedure prior to the end of the inspection. The inspectors concluded that the procedure combined with the training had provided adequate guidance for the examiners to identify, disposition, and resolve deficiencies. The procedure indicated that any evidence of leakage would be evaluated, which would identify the primary water stress corrosion cracking described by NRC Bulletin 2001-01 and addressed the type of leakage seen elsewhere.

The inspectors reviewed the completed work package documented in Maintenance Action Item 425996 and performed in accordance with Procedure QAP-410. The work package accurately documented the condition of the reactor vessel head, documented the examination of each vessel head penetration, identified the qualification of the test equipment used, and identified personnel who performed the work. In addition to this quality record, the licensee had videotaped the examination process and had indexed the penetrations. The inspectors had requested the qualification records for the examination. The licensee had not performed the qualification test for the boroscope prior to the examinations; however, the licensee performed a postexamination qualification on the boroscope that demonstrated the boroscope had the correct resolution. The licensee documented this deficiency in Condition Report 2002-0636.

During evaluation of the videotapes of the vessel head penetrations, the inspectors noted that a tape of some boroscope examinations did not have any indexing, although the condition of the penetrations could clearly be identified. After the inspectors questioned how to identify the nozzles on the videotape, the licensee initiated Condition

Report 2002-0645 because this did not meet management expectations. The inspectors concluded no violation occurred since the tapes were not used to meet any regulatory requirement.

.2 Condition of the reactor vessel head

The inspectors found by direct visual evaluation that the reactor vessel head had no indications of boric acid leakage nor any boric acid stains. The reactor vessel head had a small amount of debris/dirt located at the top under portions of the remaining reflective stainless steel insulation. The licensee could not cut out all of the permanent stainless steel insulation as planned because of concerns with cutting the head vent line. This provided several challenges: (1) the remote examinations had to be conducted with a boroscope, (2) the fiberglass insulation rings crumbled as the insulation was raised (this occurred at other locations), and (3) the low clearance of the reflective insulation made it difficult to vacuum up all of the crumbled insulation fibers and other debris.

Although the remaining reflective insulation provided a physical challenge, the inspectors noted that the examiners took compensatory actions to ensure a thorough examination. Similarly, although some fiberglass insulation pieces were present, the inspectors confirmed that the resolution of the boroscope ensured that boron deposits would have been detected. The inspectors estimated that the cameras for the boroscope and the robot multiplied the images by a factor of 2 or 3; consequently, the images of metal filings and insulation pieces looked rather large. Upon questioning, the licensee prepared a standard (i.e., a sample of metal filings, insulation filler, color sheets, against a ruler) that demonstrated that the debris on the vessel head was in fact insulation fibers.

.3 Capability to identify and characterize small boron deposits

The inspectors concluded that the examiners and equipment used during the examinations could reliably detect and accurately characterize any identified leakage. The inspectors verified that: (1) the examination team consisted of the same group of individuals, (2) the individuals had received the training on what indications looked like and actions to take if an individual identified any indications, (3) the licensee had generated a process for evaluation of deposits, (4) the licensee had implemented an independent review process of the videos taken during the examinations, and (5) the licensee used equipment with appropriate resolution. Since the work went around the clock, the same personnel did not perform all of the examinations. However, the inspectors noted that the independent assessment by the project managers ensured a consistent evaluation.

.4 Materiel deficiencies identified that required repair

There were no materiel deficiencies identified which required repair. However, the licensee identified that a dark brown substance had collected on the outside of the control element drive mechanisms and initiated Condition Report 2002-0566 to document this condition. As part of the corrective actions, the licensee collected a sample and had it analyzed. The licensee determined that the substance was reactor coolant pump oil that had atomized, carried by the control element drive mechanism ventilation system above the shroud plate. The oil collected on the vessel head and hardened. The inspectors questioned whether this substance had deposited to some degree on the stainless steel reflective insulation. The licensee concluded that the oil had hardened on the nozzles prior to depositing on the insulation. The licensee concluded that the chemical composition of the residue was consistent with a hydrocarbon and that there are no materials that would cause degradation or stress on the stainless steel nozzles.

.5 Impediments to effective examinations and/or ALARA issues

The inspectors determined that the licensee had identified one ALARA concern. The licensee had believed that boric acid on the reflective insulation provided for the radiation source term being measured. However, surveys of the insulation that had been removed found low levels of radiation. Subsequently, the licensee determined that the source term resulted from trapped contaminants in the incore instrument nozzles. The contaminants reside in these nozzles because of the relatively low flow velocities during operation. The licensee flushed one of the incore instrument penetrations, which had no effect on the source term. The licensee decided to leave the incore instrument penetrations until a future date that would allow them to take more effective methods to reduce the source term.

4OA6 <u>Meetings</u>

<u>Exit Meeting Summary</u>

.1 The senior health physics inspector presented the inspection results to Mr. J. Venable, Vice President of Operations, and other members of licensee management at the conclusion of the inspection on April 12, 2002. The licensee acknowledged the findings presented.

The inspector asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

.2 The reactor inspector presented the inspection results to Mr. J. Venable, Vice President of Operations, and other members of licensee management at the conclusion of the inspection on April 24, 2002. The licensee acknowledged the findings presented.

The inspector asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified

.3 The emergency preparedness inspector presented the inspection results to Mr. J. Lewis, Manager, Emergency Planning, and other members of licensee management during a telephonic exit interview conducted on April 30, 2002. The licensee acknowledged the findings presented.

The inspector asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

.4 The senior reactor inspector presented the inspection results to Mr. T. Gaudet, Acting General Manager, Plant Operations, and other members of licensee management at the conclusion of the inspection on June 20, 2002. The licensee acknowledged the findings presented.

The inspector asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

.5 The resident inspectors presented the inspection results to Mr. J. Venable, Vice President of Operations, and other members of licensee management at the conclusion of the inspection on July 10, 2002. The licensee acknowledged the findings presented.

The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

ATTACHMENT

PARTIAL LIST OF PERSONS CONTACTED

Licensee

S. Anders, Superintendent, Plant Security
M. Berendt, Supervisor, Systems Engineering
L. Borel, Senior Engineer, Licensing
M. K. Brandon, Manager, Licensing
G. Bratton, Quality Assurance
T. Brown, Work Week Manager
L. Dauzat, Supervisor, Health Physics
J. R. Douet, General Manager, Plant Operations
E. C. Ewing, General Manager, Plant Operations
R. M. Fili, Manager, Programs and Components Engineering
B. Fitsimmons, Steam Generator Engineer, Code Program
P. Fresneda, Engineer, Programs/Components Engineering
C. Fugate, Associate Manager, Plant Operations
T. Gaudet, Director, Planning and Scheduling
B. Houston, Technical Assistant to Vice President
J. Hunsaker, Manager, Site Support
S. Hymel, Coordinator, Human Performance
T. P. Lett, Superintendent, Radiation Protection
J. Lewis, Manager, Emergency Planning
P. McKenna, System Engineer, Systems Engineering
D. Madere, Engineer, Licensing
D. Miller, Senior Health Physicist, Health Physics
M. Mills, Coordinator, Self Assessment
B. Morrison, Supervisor, Quality
R. O'Quinn, Supervisor, Components Engineering
R. Osborne, Manager, System Engineering
W. Pendergrass, Assistant to Operations Manager
K. Peters, Director, Nuclear Safety Assurance
R. Peters, Acting Director, Nuclear Safety Assurance
G. Pierce, Chemistry Supervisor
G. Pierce, Oversight Director
B. Pilutti, Supervisor, Radiation Protection
J. Reese, Engineer, Design Engineering
J. A. Ridgel, Manager, Maintenance
R. Sebring, Senior Technician, Health Physicist
C. Talazac, System Engineer, Minor Modifications
T. E. Tankersley, Manager, Training
J. Venable, Vice President, Operations
K. Walsh, Manager, Plant Operations
G. Zetsch, Security, Senior Lead Coordinator

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-382/02002-01	NCV	Failure to maintain proper foreign material exclusion controls (Section 1R13)
50-382/02002-02	NCV	Failure to survey and control a high radiation area (Section 2OS1)
50-382/02002-03	NCV	Failure to correct the cause of voiding in the LPSI system and to take effective corrective action to preclude repetition of this condition (Section 4OA2)
50-382/02002-04	NCV	Failure to comply with Technical Specification 3.7.3 and exceeding the allowed outage time for auxiliary component cooling water pump B (Section 4OA2)

Closed

50-382/02002-01	NCV	Failure to maintain proper foreign material exclusion controls (Section 1R13)
50-382/02002-02	NCV	Failure to survey and control a high radiation area (Section 2OS1)
50-382/02002-03	NCV	Failure to correct the cause of voiding in the LPSI system and to take effective corrective action to preclude repetition of this condition (Section 4OA2)
50-382/02002-04	NCV	Failure to comply with Technical Specification 3.7.3 and exceeding the allowed outage time for auxiliary component cooling water pump B (Section 4OA2)
50-382/99001-01	VIO	Inadequate Audit Independence (Section 4OA3)
50-382/02-003-00	LER	Inoperable Auxiliary Component Cooling Water Pump due to Lack of Lubrication (Section 4OA3)

DOCUMENTS REVIEWED

The following documents were selected and reviewed by the inspectors to accomplish the objectives and scope of the inspection and to support any findings:

Westinghouse Procedure MRS 2.4.2 GEN-29, “Video Inspection and Tube Identification of Steam Generator Tubesheet,” Revision 1

Westinghouse Procedure MRS 2.4.3 GEN-44, “Visual Inspection of Plugs,” Revision 1

Report ER-W3-00-0594-00-01, “Steam Generator Degradation Assessment and Repair Criteria for RF11,” dated March 22, 2002

Waterford 3 Design Engineering Guide ISI-1-001, “Steam Generator Eddy Current Data Analysis Guidelines,” Revision 7

Electric Power Research Institute (EPRI) Report TR-107569-V1R5, “PWR Steam Generator Examination Guidelines: Revision 5; Volume 1: Requirements” Final Report, September 1997

EPRI Report TR-107621-R1, “Steam Generator Integrity Assessment Guidelines,” Revision 1, March 2000

EPRI Report TR-107620, “Steam Generator In Situ Pressure Test Guidelines,” Revision 1

Framatome Report 51-5010504-00, “Waterford-3 Fast Track Report, 10/00, 10^{TH} Refueling Outage (RF10),” dated January 3, 2001

Report “Operational Assessment of the Waterford 3 Steam Generator Tubing for Cycle 11,” Revision 1

Report ER-W3-99-0133-00-01, “Engineering Report for Demonstrating Equivalency to PWR Steam Generator Examination Guidelines Revision 5, Volume 1: Requirements,” approved March 27, 2002

Generic Letter 95-03, “Circumferential Cracking of Steam Generator Tubes,” dated April 28, 1995

Waterford 3 response letter to Generic Letter 95-03, W3F1-95-005, dated June 27, 1995

NRC letters (requesting additional information regarding Generic Letter 95-03) dated August 31 and September 21, 1995, and Waterford 3 response letter dated October 5, 1995

Generic Letter 97-05, “Steam Generator Tube Inspection Techniques,” dated December 17, 1997

Waterford 3 response letter to Generic Letter 97-05, W3F1-98-0043, dated March 17, 1998

Generic Letter 97-06, “Degradation of Steam Generator Internals,” dated December 30, 1997

Waterford 3 response letter to Generic Letter 97-06, W3F1-98-0057, dated March 30, 1998

Westinghouse Field Service Procedure CWTR3-SG-002, “Rolled Mechanical Tube Plugging and Stabilizer Installation for Waterford 3 Steam Generators With 0.750 O.D. X 0.048'' Wall Tubes Including Provisions for Restricted Access Corner Areas,” Revision 1.

Nuclear Management Manual NDE9.07, “Straight Beam Ultrasonic Examination of Bolts and Studs,” Revision 2.

Nuclear Management Manual NDE9.31, “Magnetic Particle Examination for ASME Section XI,” Revision 1.

Nuclear Management Manual NDE10.1, “VT-1 Inspections,” Revision 2.

TESTS

NUMBER	DESCRIPTION	DATE
PE-004-021	CCW “A” Heat Exchanger Performance Test	April 2000
PE-004-021	CCW “A” Heat Exchanger Performance Test	May 1998
PE-004-021	CCW “B” Heat Exchanger Performance Test	December 2001
PE-004-021	CCW “B” Heat Exchanger Performance Test	April 2000
PE-004-021	CCW “B” Heat Exchanger Performance Test	May 1998
PE-004-024	ACCW & CCW System Flow Balance - Train A	April 2002
PE-004-024	ACCW & CCW System Flow Balance - Train B	April 2002
STP-01174749	EDG A and B Water Coolers Uncertainty Analysis and STER Heat Exchanger Performance Software results	February 1999
STP-01174749	EDG Heat Exchangers Performance Test	November 1998

CALCULATIONS

NUMBER	TITLE	REVISION
EC-M95-008	Ultimate Heat Sink Design Basis	1

CONDITION REPORTS

CR-WF3-2000-0233	CR-WF3-2001-0650	CR-WF3-1996-1965
CR-WF3-2000-0612	CR-WF3-2002-0041	CR-WF3-1998-0965
CR-WF3-2001-0599	CR-WF3-1997-0200	CR-WF3-2001-0430
CR-WF3-2001-0682	CR-WF3-1996-1831	CR-WF3-2002-0339
CR-WF3-2001-0927	CR-WF3-1998-0069	CR-WF3-1996-1844
CR-WF3-2001-1015	CR-WF3-2001-1348	CR-WF3-2001-1295
CR-WF3-2002-0569	CR-WF3-2002-4465	CR-WF3-2002-0052
CR-WF3-2002-0339	CR-WF3-2002-0818	CR-WF3-2002-0947
CR-WF3-2002-1021	CR-WF3-2002-1025	CR-WF3-2002-1033
CR-WF3-2002-1069	CR-WF3-2002-1078	

MAINTENANCE ACTION ITEMS

MAI 410386
MAI 413009
MAI 413012
MAI 419595

MISCELLANEOUS DOCUMENTS

Notice of Enforcement Discretion for Entergy Station, Unit 3 (NOED 00-6-006), dated May 1, 2001

Waterford Steam Electric Station, Unit 3 - Issuance of Amendment re: Reduction in Operable Containment Fan Coolers in the Containment Cooling System (TAC MA6997), dated July 6, 2000

Chemical Cleaning of the Containment Fan Coolers (CE-TEM-007), dated May 1997

Containment Fan Cooler Performance Analysis, dated September 27, 1996

CCW/ACCW/UHS System Heath Report (2002)

LIST OF ACRONYMS USED

ALARA	as low as is reasonably achievable
CFR	Code of Federal Regulations
EPRI	Electric Power Research Institute
LER	licensee event report
LPSI	low-pressure safety injection
NCV	noncited violation
NRC	U.S. Nuclear Regulatory Commission
RWP	radiation work permit
SSU	safety system unavailability
VIO	violation