UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
SAM NUNN ATLANTA FEDERAL CENTER
61 FORSYTH STREET SW SUITE 23T85
ATLANTA, GEORGIA 30303-8931

January 21, 2004

Florida Power and Light Company
ATTN: Mr. J. A. Stall, Senior Vice President
Nuclear and Chief Nuclear Officer
P. O. Box 14000
Juno Beach, FL 33408-0420

SUBJECT: TURKEY POINT NUCLEAR PLANT - INTEGRATED INSPECTION REPORT 05000250/2003005 AND 05000251/2003005

Dear Mr. Stall:

On December 27, 2003, the US Nuclear Regulatory Commission (NRC) completed an inspection at your Turkey Point Units 3 and 4. The enclosed integrated inspection report documents the inspection findings which were discussed on January 8, 2004, with Mr. M. Pearce and other members of your staff.

The inspection examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

Based on the results of this inspection, the inspectors identified one finding of very low safety significance (Green). The finding was determined to involve a violation of NRC requirements. However, because of the very low safety significance and because the violation was entered into your corrective action program, the NRC is treating the violation as a non-cited violation (NCV) in accordance with Section VI.A of the NRC's Enforcement Policy. Additionally, a licensee-identified violation which was determined to be of very low safety significance is listed in Section 4OA7 of this report. If you contest the NCV in this report, you should provide a response, within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001; with copies to the Regional Administrator, Region II; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Senior Resident Inspector at the Turkey Point facility.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be available electronically for public inspection in the NRC Public Document

Room or from the Publicly Available Records (PARS) component of the 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).

Sincerely,

/RA/

Joel T. Munday, Chief
Reactor Projects Branch 3
Division of Reactor Projects

Docket Nos. 50-250, 50-251
License Nos. DPR-31, DPR-41

Enclosure: Inspection Report 05000250/2003005 and
05000251/2003005
w/Attachment: Supplemental Information

cc w/encl: (See page 3)

cc w/encl:
T. O. Jones
Site Vice President
Turkey Point Nuclear Plant
Florida Power and Light Company
Electronic Mail Distribution

Walter Parker
Licensing Manager
Turkey Point Nuclear Plant
Florida Power and Light Company
Electronic Mail Distribution

Michael O. Pearce
Plant General Manager
Turkey Point Nuclear Plant
Florida Power and Light Company
Electronic Mail Distribution

Don Mothena, Manager
Nuclear Plant Support Services
Florida Power & Light Company
Electronic Mail Distribution

Rajiv S. Kundalkar
Vice President - Nuclear Engineering
Florida Power & Light Company
Electronic Mail Distribution

M. S. Ross, Attorney
Florida Power & Light Company
Electronic Mail Distribution

Linda Tudor
Document Control Supervisor
Florida Power & Light Company
Electronic Mail Distribution

Attorney General
Department of Legal Affairs
The Capitol
Tallahassee, FL 32304

William A. Passetti
Bureau of Radiation Control
Department of Health
Electronic Mail Distribution

County Manager
Metropolitan Dade County
Electronic Mail Distribution

Craig Fugate, Director
Division of Emergency Preparedness
Department of Community Affairs
Electronic Mail Distribution

Curtis Ivy
City Manager of Homestead
Electronic Mail Distribution

Distribution w/encl: (See page 4)

Distribution w/encl:
E. Brown, NRR
C. Evans (Part 72 Only)
L. Slack, RII EICS
RIDSNRRDIPMLIPB
PUBLIC

OFFICE	DRP/RII	DRP/RII	DRP/RII	DRP/RII	DRS/RII	DRS/RII	DRS/RII
SIGNATURE		kg	jm (for)	sn	ml (for)	rh	sv
NAME	KWeaver:vyg	KGreenBates	JHanna	SNinh	BCrowley	RHamilton	SVias
DATE	1/ /2004	1/19/2004	1/21/2004	1/15/2004	1/15/2004	1/15/2004	1/15/2004
E-MAIL COPY?	YES NO	YES NO	YES NO	YES NO	YES NO	YES NO	YES NO
PUBLIC DOCUMENT							
OFFICE	DRS/RII	DRS/RII	DRS/RII				
SIGNATURE	sc (for)	df	mm				
NAME	RCarrion	DForbes	MMaymi				
DATE	1/15/2004	1/15/2004	1/15/2004				
E-MAIL COPY?	YES NO	YES NO	YES NO				
PUBLIC DOCUMENT							

OFFICIAL RECORD COPY DOCUMENT NAME: C:\ORPCheckout\FileNET\ML040220017.wpd

U.S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket Nos:	50-250, 50-251
License Nos:	DPR-31, DPR-41
Report No:	05000250/2003005, 05000251/2003005
Licensee:	Florida Power & Light Company (FP&L)
Facility:	Turkey Point Nuclear Plant, Units 3 & 4
Location:	9760 S. W. 344th Street Florida City, FL 33035
Dates:	September 28, 2003 - December 27, 2003
Inspectors:	K. Weaver, Senior Resident Inspector J. Hanna, Acting Senior Resident Inspector K. GreenBates, Resident Inspector R. Carrion, Project Engineer (Section 2OS1) B. Crowley, Senior Reactor Inspector (4OA5) D. Forbes, Health Physicist, (Section 2PS2) R. Hamilton, Health Physicist, (Section 2OS2, 4OA1) M. Maymi, Reactor Inspector (IR07) S. Vias, Reactor Inspector (IR08)
Approved by:	Joel T. Munday, Chief Reactor Projects Branch 3 Division of Reactor Projects

Enclosure

CONTENTS

SUMMARY OF FINDINGS

IR 05000250/2003-005, 05000251/2003-005; 09/28/2003 - 12/27/2003; Turkey Point Nuclear Power Plant, Units 3 and 4; Operability Evaluations.

The report covered a three month period of inspection by resident inspectors and announced inspections by three region based engineering inspectors and three region based radiation specialists. One Green non-cited violation (NCV) were identified. The significance of most findings is identified by their color (Green, White, Yellow, Red) using IC 0609, "Significance Determination Process" (SDP). Findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Overnight Process", Revision 3, dated July 2000.

A. Self-Revealing Finding

Cornerstone: Mitigating Systems

- Green. A self revealing non-cited violation was identified for failure to comply with 10 CFR 50, Appendix B, Criterion III, "Design Control." The licensee failed to identify and specify in procedures the appropriate acceptance criteria for the main oil pump (MOP) internals clearances and the MOP suction check valve leakage, to ensure the operability of the 'B' Auxiliary Feedwater Pump (AFW). As a result, during surveillance testing, the 'B' AFW Pump experienced a lubrication failure which damaged the pump outboard thrust bearings.

  This finding is greater than minor because it involved the design control attribute of the mitigating system cornerstone, which could affect the objective of ensuring that equipment is available and capable of responding to an event. The finding was of very low safety significance in accordance with the Significance Determination Process (SDP) Phase 1 worksheet, because it did not represent an actual loss of the safety function of the AFW system and it did not represent an actual loss of safety function of a single train of AFW for greater than the Technical Specification allowed outage time. (Section 1R15)

B. Licensee Identified Violation

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

REPORT DETAILS

Summary of Plant Status:

Unit 3 operated at full power during most of the inspection period with the following exceptions. On September 29, Unit 3 reduced power to approximately 91% due to temperature control problems associated with cooling the main turbine generator exciter. Following maintenance activities, Unit 3 was returned to full power on September 30. On December 2, Unit 3 reduced power to 25% for turbine valve testing, flux map instrumentation repair, and turbine plant cooling water heat exchanger cleaning. The plant subsequently commenced a power increase following the maintenance activities. However, during the power escalation, when Unit 3 had achieved approximately 60% power, the unit experienced an unexpected malfunction of the turbine governor control system. Due to this malfunction, on December 6, Unit 3 reduced power from 60% power (Mode 1) to 2% power (Mode 2) and took the turbine offline to repair the turbine governor control system. Following repairs of the turbine governor control system, Unit 3 commenced a power escalation and returned to full power on December 8, where it remained for the rest of the inspection period.

Unit 4 began the inspection period at approximately 94% power and in a power coastdown in preparation for a refueling outage. On October 6, Unit 4 shutdown for a refueling outage and remained shutdown until November 4, when the plant was restarted. On November 4, Unit 4 operators made the reactor critical and commenced a power escalation. On November 7, Unit 4 achieved full power and remained at full power for the rest of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity (Reactor-R)

1R01 Adverse Weather Protection

a. Inspection Scope

On November 4, 2003, in response to a declared Tornado Watch, the inspectors performed a walkdown of outside structures and various risk significant systems exposed to the elements. The inspectors verified that these systems would remain functional during high winds and were adequately protected from missile debris. The inspectors reviewed Procedure 0-ONOP-103.3, “Severe Weather Preparations,” and Section 5.1 of the Updated Final Safety Analysis Report (UFSAR) in order to verify the licensee’s compliance.

Additionally, the inspectors performed a walkdown of the following three risk significant systems to verify that these systems would remain functional during cold weather conditions. During applicable cold weather days in December 2003, the inspectors verified that the preventive maintenance activities associated with Procedure 0-ONOP-103.2 “Cold/Hot Weather Conditions,” for cold protection systems were appropriately scheduled and completed prior to and during the onset of cold weather. The inspectors verified that compensatory actions were implemented for degraded or inoperable instrument air compressors, AFW system nitrogen tanks, and emergency diesel generator (EDG) lube oil temperatures and cold weather protection equipment.

- Unit 3 AFW Nitrogen Back-up System
- Unit 3 and Unit 4 Instrument Air System
- Unit 3 and Unit 4 EDG System

The inspectors also reviewed the licensee's corrective action program for adverse weather related items listed in the attachment to ensure that discrepancies were being identified and appropriately resolved.

b. Findings

No findings of significance were identified**.**

1R04 Equipment Alignment

a. Inspection Scope

Partial Equipment Walkdowns

The inspectors conducted three partial alignment verifications of the safety-related systems listed below. The inspectors reviewed the operability of a redundant train or backup system/train while the other trains were inoperable or out of service, and/or a remaining operable system/train with a high risk significance for a current plant configuration. These inspections included reviews of plant lineup procedures, operating procedures, and piping and instrumentation drawings, which were compared with observed equipment configurations to verify that the critical portions were correctly aligned and that they identified any discrepancies that could affect operability.

- Unit 4, 4B 4.16 KV Switchgear Room while the 4A 4.16 KV Switchgear Room was racked out for maintenance conducted during the week of October 14 and 15, 2003.

- Unit 4, B EDG, 4.16 KV Switchgear and 480V Motor Control Center while refueling was in progress with the 4B RHR system inservice and train 4B as the risk significant protected train, October 22 and 24, 2003.

- Unit 4, Fuel Pool Cooling, Purification and Ventilation System while all fuel was removed from the Reactor Vessel and was located in the Spent Fuel Pool, conducted during the week of October 21,2003.

Complete System Walkdown

On October 14 and 15, 2003, the inspectors conducted a detailed review of the alignment and condition of the 4B EDG while the 4A EDG was out of service for planned maintenance. The inspectors used the procedures and other documents listed in the Attachment, as well as applicable chapters of the UFSAR, to verify proper system alignment. The detailed review also verified electrical power requirements, labeling, hangers and support installation, and associated support systems status. Operating pumps were examined to ensure that vibration levels were not elevated, pump leakoff was not excessive, bearings were not hot to the touch, and the pumps were properly ventilated. The walkdowns also included evaluation of system piping and supports against the following considerations:

- Piping and pipe supports did not show evidence of water hammer.
- Oil reservoir levels indicated normal.
- Snubbers did not indicate any observable hydraulic fluid leakage.
- Hangers were within the setpoints.
- Component foundations were not degraded

A review of outstanding maintenance work orders was performed to verify that the deficiencies did not significantly affect the EDG system safety function. In addition, the inspectors reviewed the condition report database to verify that EDG equipment alignment problems were being identified and appropriately resolved.

b. Findings

No findings of significance were identified.

1R05 Fire Protection

a. Inspection Scope

The inspectors toured the following ten plant areas during this inspection period to evaluate conditions related to control of transient combustibles and ignition sources, the material condition and operational status of fire protection systems, and selected fire barriers used to prevent fire damage or fire propagation. The inspectors reviewed these activities against provisions in the licensee’s off Normal Operating Procedure, 0-ONOP-016.8, “Response to a Fire/Smoke Detection System Alarm,” Administrative Procedures 0-SME-091.1, “Fire and Smoke Detection System Annual Test”; O-ADM-016.4 “Fire Watch Program”; 0-ADM-016,“Fire Protection Plan, and 10 CFR Part 50, Appendix R. In addition, the inspectors reviewed the condition report database to verify that fire protection problems were being identified and appropriately resolved. The following areas were inspected:

- Unit 4 Charging Pump Room (Fire Zone 45)
- Unit 3 Charging Pump Room (Fire Zone 55)
- Unit 4 480V Load Center AB Room (Fire Zone 93)

- Unit 4 480V Load Center CD Room (Fire Zone 94)
- Unit 3 480V Load Center AB Room (Fire Zone 95)
- Unit 3 480V Load Center CD Room (Fire Zone 96)
- Unit 4 West Electrical Penetration Room (Fire Zone 27)
- Unit 4 Pipe and Valve Room (Fire Zone 30)
- Unit 4 Safety Injection Pump Room (Fire Zone 52)
- Units 3 and 4 Auxiliary Building Hallway - Elevation 18’ (Fire Zone 58)

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures

.1 External Flooding

a. Inspection Scope

The inspectors completed a flood protection walkdown of the auxiliary building on November 13, 2003. The inspectors performed the review due to the sustained and heavy precipitation during this time period. The inspectors conducted the walkdown to verify that the licensee had implemented adequate protection from external flooding. The inspection included wall penetration seals, level alarms, doors credited in the licensee’s flood protection analysis, etc. Additionally, the inspectors performed in-office reviews of the external flooding calculations listed in the Attachment to this report. The inspectors also reviewed the licensee’s corrective action program for flooding related items to ensure that discrepancies were being identified and appropriately resolved. Licensee documents reviewed during the inspection are listed in the Attachment.

b. Findings

No findings of significance were identified.

.2 Internal Flooding

a. Inspection Scope

During the week of November 13, the inspectors reviewed the UFSAR for Internal Flooding Criteria, to identify risk significant areas that could be affected by internal flooding and to verify flood mitigation plans and equipment were consistent with the design requirements. The Unit 3 and Unit 4 RHR rooms were considered subject to flooding should a fire protection system piping break occur. The Unit 3 and Unit 4 RHR rooms were examined to evaluate the condition of flood protection equipment, such as sumps and level alarms. The inspectors reviewed past condition reports for flooding related items to ensure that discrepancies were being identified and appropriately resolved.

b. Findings

No findings of significance were identified.

1R07 Biennial Heat Sink Performance

a. Inspection Scope

The inspectors reviewed inspection records, performance test results, preventive maintenance procedures, and other documentation to ensure that heat exchanger (HX) deficiencies that could mask or degrade performance were identified and corrected. Risk significant heat exchangers reviewed included the RHR heat exchangers, the High Head Safety Injection (HHSI) pump coolers and the Component Cooling Water (CCW) heat exchangers.

The inspectors reviewed CCW HX performance test completed procedures, test data trending and plots, Eddy Current Test results, tube plugging margins, CCW HX cleaning procedures and completed work orders. Additionally RHR HX design information, performance test results and calculations, CCW flow requirements safety evaluation, and CCW flow balance completed procedures that verify minimum flow requirements to the RHR HXs were also reviewed. The inspectors also reviewed HHSI pump cooler design information, system inservice test results, cooler flow instrument operator logs and procedure to verify minimum flow requirements, and CCW minimum flow and heat load requirements to the coolers. These documents were reviewed to verify that test results were consistent with design acceptance criteria, testing methodology and assumptions were adequate, inspection methods and performance of the HXs under the current maintenance frequency were adequate, and to verify minimum flow requirements and HX design basis were being maintained.

The inspectors also reviewed the general health of the Intake Cooling Water (ICW) system via review of the ICW inspection program basis document, crawl thru inspection reports with recommended actions, CCW supply basket strainers cleaning procedure and completed work orders, and discussions with the ICW system engineer. Condition reports were reviewed for potential common cause problems and problems which could affect system performance to confirm that the licensee was entering problems into the corrective action program and initiating appropriate corrective actions. These condition reports included actions regarding the Turbine Plant Cooling Water (TPCW) isolation valves degradation issues, ICW pump shaft, packing leakage and vibration issues, and pump check valve issues. In addition, the inspectors conducted a walkdown of all selected HXs and major components for the ICW system to assess general material condition and to verify that the installed configuration was consistent with design drawings.

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection (ISI)

a. Inspection Scope

The inspectors observed Unit 4 in-process ISI work activities during the final outage of the 3rd interval, 3rd ISI period and reviewed selected ISI records. The observations and records were reviewed for compliance to the Technical Specifications and the applicable Code (ASME Boiler and Pressure Vessel Code, Section XI, 1989 Edition, with no Addenda).

The areas that were reviewed included: two NDE activities (volumetric and surface examinations), one exam on a pressure boundary weld, SG inspection activities and the Flow-Accelerated Corrosion (FAC) Monitoring Program.

The following Unit 4 ISI examinations were observed:

Ultrasonic (UT)	18–FWA-2401-3A		Augmented (Nozzle ramp to 1 diameter on elbow)
	14–FWA-2401-28		Augmented (Nozzle ramp to 1 diameter on elbow)
	18–FWA-2401-29		Augmented (Nozzle ramp to 1 diameter on elbow)
	6-BCD-2406-32C	C5.51	(Pipe to Valve SGB-4-009)
	31-MSC-2403-1A	C5.51	(Nozzle to Reducer)
	26-MSC-2403-1	C5.51	(Reducer to Elbow)
Magnetic (MT)	6-BCD-2406-32C	C-F-2	(Pipe to Valve SGB-4-009)

Qualification and certification records for examiners, equipment and consumables, and nondestructive examination (NDE) procedures for the above ISI examination activities were reviewed. In addition, a sample of ISI issues in the licensee's corrective action program were reviewed for adequacy.

b. Findings:

No findings of significance were identified.

1R11 Licensed Operator Requalification

a. Inspection Scope

On November 19, 2003, the inspectors observed and assessed licensed operator actions on the simulator to a steam generator tube rupture accident scenario that also involved the failure of numerous critical safety components. The inspectors specifically evaluated the following attributes related to operating crew performance. Licensee procedures and documents reviewed are included in the Attachment to this report.

- Clarity and formality of communication
- Ability to take timely action to safely control the unit
- Prioritization, interpretation, and verification of alarms
- Correct use and implementation of Emergency Operating Procedures and Emergency Plan Implementing Procedures
- Control board operation and manipulation, including high-risk operator actions
- Oversight and direction provided by Operations supervision, including ability to identify and implement appropriate Technical Specification actions, regulatory reporting requirements, and emergency plan actions and notifications
- Effectiveness of the post training critique.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness

a. Inspection Scope

The inspectors reviewed the following three equipment problems and associated condition reports to verify the licensee's maintenance efforts met the requirements of 10 CFR 50.65 (the Maintenance Rule) and Plant Procedures: PMI-5035, "Maintenance Rule Program", PMP-5035-MRP-001 "Maintenance Rule Program Administration" and 12-EHP-5035-MRP-001 "Maintenance Rule Program Administration." The inspectors' efforts focused on maintenance rule scoping, characterization of the failed components, risk significance, determination of a(1) classification, corrective actions, and the appropriateness of established performance goals and monitoring criteria. The inspectors also attended applicable expert panel meetings, interviewed responsible engineers, and observed some of the corrective maintenance activities. Furthermore, the inspectors verified whether equipment problems were being identified at the appropriate level and entered into the corrective action program.

- Unit 4, Area Radiation Monitoring System (ARMS) Channel 5, (breakdown after repair) post maintenance test (PMT) conducted on October 23, 2003
- Failure of the 'B' AFW Pump on August 18, 2003, conducted on November 6 and 10, 2003
- Failure of the 'C' AFW Pump to pass its post maintenance test on December 11, 2003 after design modification, conducted on December 17-19, 2003.

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessments and Emergent Work Control

a. Inspection Scope

The inspectors completed in-office reviews and control room inspections of the licensee's risk assessment of seven emergent or planned maintenance activities. The inspectors compared the licensee's risk assessment and risk management activities against the requirements of 10 CFR 50.65(a)(4); the recommendations of Nuclear Management and Resource Council 93-01, "Industry Guidelines for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," Revision 3; and Procedures 0-ADM-068, "Work Week Management" and O-ADM-225, "On Line Risk Assessment and Management." The inspectors also reviewed the effectiveness of the licensee's contingency actions to mitigate increased risk resulting from the degraded equipment. The inspectors evaluated the following risk assessments during the inspection:

- Unit 4, Elevated outage risk due to ARMS Channel 5 out of service on October 23, 2003.
- Unit 4, Elevated outage risk due to Process Monitor R19 out of service on October 28, 2003 in conjunction with pending startup of reactor coolant pump which has a past repeat history of causing Process Monitors R11 & R12 to fail (3 simultaneously out of service would place the plant in a high outage risk condition).
- Unit 4, Elevated outage risk due to emergent work in the fuel canal on October 22, 2003 (Diver risk vs Drain-down risk to perform maintenance).
- Inadvertent drain-down of refueling water storage tank into charging pump room (4200 gal) on October 20, 2003 .
- Maintenance and tagout of containment emergency spray back-up solenoid valves SV-4-2910 and 2909 on October 23, 2003.
- Unit 4, Elevated outage risk due to '4A' 4160 Volt Bus Outage on October 14, 2003.
- Unit 4, Increased RCS leakage due to leaking letdown thermal relief valve RV-4-304 and leaking throttle valve HCV-187 when establishing conditions to perform U4 Charging pump IST test on December 20, 2003.

b. Findings

No findings of significance were identified.

1R14 Personnel Performance During Non-Routine Plant Evolutions and Events

a. Inspection Scope

This inspection evaluated operator, maintenance and engineering response and performance for non-routine plant evolutions to ensure they were appropriate and in accordance with the required procedures. The inspectors also evaluated performance problems to ensure that they were entered into the corrective action program. The following events or evolutions were reviewed:

- Plant operators conducted a controlled shutdown of Unit 4 on October 6, 2003, for the U4CY 21 refueling outage. The inspectors observed the conduct of control room activities, procedure use and adherence, plant equipment manipulations and reactor engineering support activities.

- On October 22, 2003, the inspectors observed operator and personnel response to a small fire on the first floor of the Turbine building, caused by a weld spark igniting a rag.

- On November 4, 2003, the inspectors observed operator performance during a reactor startup and approach to criticality. The inspectors observed the conduct of control room activities, procedure use and adherence, and plant equipment manipulations.

- Plant operators conducted a controlled downpower of Unit 3 on December 6, 2003, due to a malfunction in the turbine governor control system. Mode 2 was entered for troubleshooting and repairs. The unit returned to full power on December 8, 2003.

- On December 20, 2003, while increasing excess letdown in order to establish conditions to perform Unit 4 Charging Pump In-Service Testing, the inspectors observed that plant operators responded promptly when a unexpected decrease of Pressurizer level and Volume Control Tank level occurred.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the following six interim disposition and operability determinations associated with the following condition reports to ensure that Technical Specification operability was properly supported and the system, structure or component remained available to perform its safety function with no unrecognized increase in risk. The inspectors reviewed the UFSAR, applicable supporting documents and procedures, and interviewed plant personnel to assess the adequacy of the interim condition report disposition.

- CR 03-2306 — 3A EDG, Wrong oil added to system
- CR 03-3524 — Unit 4, Evaluation and verification that a fuel bundle nozzle cap found in the fuel pool after fuel was replaced into the core, was not from a fuel assembly currently in the vessel.
- CR 03-2174 — Unit 4, Potential damage to reactor vessel head vent due to unexpected impact during a polar crane lift.
- CR 03-2174 — AFW A & C pumps operability evaluation following the failure of B pump on August 18, 2003.

- CR 03-3181 Unexpected lateral movement fuel element deflection during core offload for fuel bundle nos. NP54, YY39, NP04 and YY46
- CR 03-2319-1 Westinghouse fuel potential generic defects with new U4C21 fuel bundles due to miscalibrated gauge.

b. Findings

AFW Pump 'B' Failure

Introduction. A self revealing Green NCV was identified for failure to identify appropriate acceptance criteria for AFW main oil pump (MOP) internal clearances, and, AFW MOP suction check valve leakage. As a result, the 'B' AFW pump experienced a main lubricating oil system failure which severely damaged the pump outboard thrust bearings.

Description. On August 18, 2003, the licensee performed a routine surveillance test of the 'B' AFW Pump. Two minutes after the pump was started, a local operator checked the oil pressure, found the gage indicating 0 psig and tripped the pump manually. Subsequent investigation revealed that the pump had experienced a main lubricating oil system failure which severely damaged the pump outboard thrust bearings. The root cause of the lubrication failure was excessive clearances of the MOP in conjunction with back leakage through a check valve designed to keep the oil suction piping primed.

The excessive clearances found on the MOP during the licensee's investigation caused a high lubricating oil recirculation flow which resulted in the inability of the MOP to prime itself. The MOP was found to have a 0.0115" gap between the sides of gears and the housing. Maintenance Procedure 0-PMM-075.5, "Auxiliary Feedwater Pump Turbine and Turbine Oil Pump Inspection and Overhaul" required values of 0.006" to 0.008" but were based on non-critical use of the pump. The procedure should have incorporated a 0.003" to 0.005" requirement per Dresser-Rand's recommendation due to critical use of the pump. In addition, the licensee determined that a newly replaced check valve in the MOP suction line, designed to keep the oil suction piping primed, did not sufficiently seal and resulted in the suction line emptying back into the sump. The licensee determined that the leakage acceptance test for the check valve was insufficient to accurately identify that the valve was leak tight. The existing acceptance criteria identified in Procedure 0PMM-075.5, "Auxiliary Feedwater Pump Turbine and Turbine Oil Pump Inspection and Overhaul," was 4mL per 6 minutes (80 drops per 6 minutes), which exceeded the amount necessary to ensure the suction piping remained full of oil. As a result of these two design deficiencies, the MOP failed to prime when started and resulted in damaging the AFW B Pump bearings.

As part of the corrective action for this failure, the licensee revised the acceptance criteria and rebuilt the MOP with a tolerance of 0.004". The licensee also calculated a new leakage acceptance criteria for the lubrication oil check valve of 3 drops per 10 minutes, and has subsequently incorporated this value into maintenance procedures. This new leakage acceptance criteria is to ensure that the check valve could perform its design function of maintaining the lubricating oil suction piping primed. Additionally, suction and discharge lines of the MOP were changed to provide loop seals on both sides of the pump. These modifications were installed to maintain oil in the MOP pump while the pump was running even if the lubricating suction line was drained.

Analysis. The licensee's failure to appropriately incorporate adequate acceptance criteria into the maintenance procedures for the MOP gear clearances and the MOP suction check valve leakage was a performance deficiency that ultimately led to the AFW B Pump failure. This finding was greater than minor because it involved the design control attribute of the mitigating system cornerstone which could affect the objective of ensuring that equipment is available and capable to respond to an event. The finding was evaluated using the SDP and was determined to be of very low safety significance in accordance with the SDP Phase 1 worksheet, because the failure did not represent an actual loss of a safety function of the AFW system, nor did it represent an actual loss of safety function of a single train of AFW for greater than the Technical Specification allowed outage time.

Enforcement. 10 CFR 50, Appendix B, Criterion III, "Design Control," required in part that "measures shall be established for the selection and review for suitability of application of materials, parts, equipment, and processes that are essential to the safety-related functions of the structures, systems and components." Contrary to the above, the licensee failed to appropriately review for suitability of application of materials, parts, equipment, and processes that were essential to the safety-related functions of the main lube oil system for the 'B' AFW system design. Specifically, the licensee failed to acquire from the vendor and specify in procedures the appropriate acceptance criterion for the MOP pump gear clearances to ensure the operability of the 'B' AFW Pump. Additionally, the licensee failed to perform appropriate evaluations and specify in procedures an acceptable limit for leakage past the lubricating oil check valve to ensure that it could perform its design function to keep the lubricating oil suction piping primed. As a result, on August 18, 2003, during a routine surveillance test of the 'B' AFW Pump, the pump experienced a lubrication failure which severely damaged the pump outboard thrust bearings. Because of the very low safety significance and the licensee's action to place the issue in their corrective action program (CR 03-2174), this violation is being treated as a non-cited violation in accordance with Section VI.A.1 of the Enforcement Policy: NCV050000250, 251/20003005-01, Failure to Identify and Use an Appropriate Acceptance Criteria for the Mail Oil Pump Internals Clearances and Main Oil Pump Suction Check Valve Leakage.

1R16 Operator Work Around

a. Inspection Scope

The inspectors reviewed the November 2003 Operator Work Around list and their effect on the plant emergency operating procedures. The inspectors completed the review to verify that the cumulative effect of operator work arounds did not challenge operators' response to plant transients and events. Additionally the inspectors discussed these potential effects with control room supervision and operators. Furthermore, the inspectors reviewed the current out of service equipment logs and walked down the control rooms to verify work arounds were being identified and properly entered into the corrective action program. The administrative procedures and corrective action documents reviewed are listed in the Attachment to this report.

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modification

a. Inspection Scope

The inspectors reviewed the documentation for Plant Change and Modification (PC/M) 02-006 to alter the start signal time delay for the Control Room Emergency Ventilation System. As part of PC/M 02-006, the inspectors reviewed the 10 CFR 50.59 screening, safety classification determination, seismic evaluation and Appendix R review performed by the licensee, and verified that Technical Specification changes and NRC approval were not required for the modification. The inspectors also observed portions of the interim and permanent system installation per the approved work order, including the breeching of fire barriers and Class 1 seismic walls and structures. Furthermore, the inspectors conducted walkdowns to verify proper installation and assure that the impact on Technical Specification and safety-related equipment was adequately addressed.

b. Findings

No findings of significance were identified.

1R19 Post Maintenance Testing

a. Inspection Scope

For the six post maintenance tests listed below, the inspectors reviewed the test procedures and either witnessed the testing and/or reviewed test records to determine whether the scope of testing adequately verified that the work performed was correctly completed and demonstrated that the affected equipment was functional and operable. The inspectors verified that the requirements of procedure 0-ADM-737, Post Maintenance Testing, were incorporated into test requirements. Procedures reviewed by the inspectors as a basis for acceptance are listed in the Attachment. The inspectors reviewed the following work orders (WO) and/or procedures:

- WO 33013991 — N-4-42B NIS Power Range B Channel II HI, Repair of High Voltage Power Supply
- WO 33014171 — N-3-42B NIS Power Range Channel II, Repair of Gain Potentiometer
- WO 32005598 & 32005593 — FCV-4-499 SG C Feedwater Bypass Flow Control Valve (CR 02-0542)

• WO 3302203	C AFW PMT on December 19, 2003 after corrective action completion of tubing modifications, overhaul of the MOP and failed PMT due to debris in oil (CR 03-4169).
• Procedure 4-OSP-203.2	Unit 4 Train A Engineered Safequards Integrated Test conducted on October 22, 2003

b. Findings

No findings of significance were identified.

1R20 Refueling and Outage Activities

a. Inspection Scope

The inspectors reviewed the outage plans and contingency plans for the Unit 4 refueling outage, conducted October 6 thru November 7, 2003, to confirm that the licensee had appropriately considered risk, industry experience, and previous site-specific problems in developing and implementing a plan that assured maintenance of defense-in-depth. During the refueling outage the inspectors observed portions of the shutdown and cooldown processes and monitored licensee controls over the outage activities listed below. In addition, the inspectors also reviewed the licensee's corrective action program to verify that the licensee was identifying problems related to refueling outage activities at an appropriate threshold and entering them into the corrective action program.

Outage Risk
Prior to the start of the refueling outage the inspectors reviewed the outage risk assessment with the licensee. The risk assessment was planned according to plant Procedure O-ADM-051, "Outage Risk Management." During the outage the inspectors verified that the outage unit risk described in daily status sheets was consistent with that described in the plan.

Clearance Activities
The inspectors performed random checks of clearance activities during the outage to verify that activities were conducted in accordance with Procedures O-ADM-212 "In-Plant Equipment Clearance Orders" and O-ADM-212.1 "Operations In-Plant Equipment Clearance Orders." A detailed review was performed of a clearance error that inadvertently drained water from the Unit 4 Refueling Water Storage Tank.

Refueling Activities
The inspectors observed fuel offload and reload activities from the control room and spent fuel pool areas and verified activities were conducted in accordance with Procedure 4-OSP-040.2, "Refueling Shuffle." The inspectors also reviewed licensee evaluation and verification activities to assure that all fuel bundles currently in the vessel had fuel bundle nozzle caps after a loose cap was found in the spent fuel pool.

RCS Instrumentation
The inspectors verified that the cooldown rate during the initial plant cooldown did not exceed Technical Specification limits. RCS pressure and level indications were observed during periods of reduced inventory to ensure adequate core cooling was maintained. The inspectors also verified that instrument uncertainty was properly accounted for.

Electrical
The inspectors monitored that electrical lineups were in accordance with the Risk Refueling Outage Assessment Plan. System configurations were monitored during planned electrical bus outages and engineered safeguards integrated testing that verified adequate power sources were maintained.

Decay Heat Removal System Monitoring
The inspectors verified that decay heat removal system components were functioning properly and that parameters remained within procedural and Technical Specification limits.

Spent Fuel Pool Cooling System Operation
The inspectors verified that the spent fuel pool cooling system was protected as described in the outage risk assessment. Temperatures were monitored when the core was completely offloaded to verify proper cooling. Activities that could affect water level were assessed using Procedure 4-OSP-075.4, "Filling/Draining the Refueling Cavity and the Spent Fuel Pool Transfer Canal."

Inventory Control
The inspectors monitored inventory control during the outage (e.g., when vessel level was lowered to allow detensioning of the reactor vessel head bolts) to verify that proper water level was maintained for core cooling.

Reactivity Control
The inspectors verified that the licensee was controlling Unit 4 reactivity in accordance with Technical Specifications. The inspectors verified that activities and components which could cause unexpected reactivity changes were identified in the outage risk plan and daily activity plans and were controlled accordingly.

Heatup and Startup Activities
The inspectors monitored portions of plant heatup, initial criticality, and power ascension to verify that mode changes were made with the required equipment operable. RCS boundary leakage was monitored to verify that leakage requirements were met.

Containment Closeout
The inspectors conducted several walkdowns of the Unit 4 Containment during the refueling outage. On October 29, 2003, a final walkdown of containment was conducted while the unit was at normal operating temperature and pressure to inspect for RCS leaks and debris that could enter the containment sumps.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing

a. Inspection Scope

The inspectors either reviewed or witnessed the following surveillance tests to verify that the tests met the Technical Specifications, the UFSAR, the licensee's procedural requirements and demonstrated the systems were capable of performing their intended safety functions and their operational readiness.

- Procedure 4-OSP-203.1/4-OP-201 — 4A Safety Injection with Loss of Offsite Power performed on October 22, 2003 (IST).
- WO 33019942 — Rod Control Cabinets Test performed on October 24, 2003.

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications

a. Inspection Scope (7111123)

The inspectors completed a review of the following two active temporary modifications and the supporting safety evaluation. The inspectors compared the temporary modification package against the requirements established in Administrative 0-ADM-503, Control and Use of Temporary System Alterations (TSA), and system requirements contained in the UFSAR. The inspectors completed in-office reviews and walkdown verifications of system restoration on November 21 and December 23, 2003. Documents reviewed during the inspection are listed in the Attachment to this report.

- TSA 3-03-05-17 "Disconnect Broken 3C 4KV Bus Lockout Relay"
- TSA 3-03-006-027 "3A LC Undervoltage Test Switch"

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstones: Occupational Radiation Safety (OS) and Public Radiation Safety (PS)

2OS1 Access Control To Radiologically Significant Areas (71121.01)

a. Inspection Scope

Access Controls. Licensee program activities for monitoring workers and controlling access to radiologically-significant areas and tasks during the current Unit 4 (U4) refueling outage were inspected. The inspectors evaluated procedural guidance; directly observed implementation of administrative and established physical controls in both the containment and auxiliary building; assessed worker exposures to radiation and radioactive material; and appraised radiation worker and technician knowledge of, and proficiency in implementing Radiation Protection (RP) program activities.

Occupational workers' adherence to selected Radiation Work Permits (RWPs) and Health Physics Technician (HPT) proficiency in providing job coverage were evaluated through direct observations, review of selected exposure records and investigations, and interviews with licensee staff. Independent surveys were made by inspectors of areas in the auxiliary building and U4 containment building. Occupational exposure data associated with direct radiation, potential radioactive material intakes from exposure to direct radiation sources and to discrete radioactive particles were reviewed and assessed independently.

RP program activities were evaluated against 10 CFR 19.12; 10 CFR 20, Subparts B, C, F, G, and J; UFSAR details in Section11, Waste Disposal and Radiation Protection System; Technical Specification Sections 6.8, Procedures and Programs, and 6.12, High Radiation Area (HRA); and approved licensee procedures. Licensee guidance documents, records, and data reviewed within this inspection area are listed in Section 2OS1 of the report Attachment.

Problem Identification and Resolution. Licensee condition reports associated with radiological controls, personnel monitoring, and exposure assessments were reviewed and discussed with responsible licensee representatives. The inspectors assessed the licensee's ability to identify, characterize, prioritize, and resolve the identified issues in accordance with the licensee procedures and documents listed in Section 4OA1 of the report Attachment.

b. Findings

No findings of significance were identified.

2OS2 ALARA Planning and Controls (71121.02)

a. Inspection Scope

Inspectors identified six jobs that were expected to have the highest cumulative radiation exposure and reviewed the associated ALARA packages. This review included incorporation of industry experience, the use of temporary shielding, monitoring of airborne radioactivity and effectiveness of contamination controls. The RWPs were reviewed for consistency with the planning documentation and logical task breakdown. A seventh job, scaffold erection and tear down, with significant scope expansion was later reviewed and tracked for revisions of RWP, dose estimates and application of additional controls. The lead individual responsible for scaffolding was interviewed to determine the cause of the scope expansion. Documented work ALARA reviews were examined and discussed with the scaffolding lead. Plant collective exposure trends and source terms were discussed with ALARA and Chemistry supervision.

Inspectors interviewed workers from several disciplines to evaluate the adequacy of supervision in the field and the sufficiency of Health Physics (HP) coverage. Several HPTs, both vendor and utility, were interviewed to determine if there would be any reluctance to stop work if unsafe conditions would be created or if the job could not be adequately covered.

Inspectors observed several containment and auxiliary building activities using the licensees remote monitoring facility. The inspectors were able to assess the sites integration of remote visual and radiological monitoring with on-scene coverage. The inspectors toured containment evaluating HP controls and practices and performed independent surveys of the lower elevation of containment. The inspectors attended pre-job briefings for the lower vessel inspection, scaffold erection, and repair of fuel handling equipment using divers.

Selected ALARA initiatives associated with the U4 outage were conducted. Shutdown chemistry and the ensuing crud burst, oxygenation and results of subsequent cleanup were discussed with Primary Chemistry personnel. ALARA, HP, Chemistry and Decon personnel were interviewed to evaluate source term control activities to include decontamination to remove surface contamination, temporary shielding installation and removal, control of spread of contamination, hotspot elimination, taking advantage of the shielding afforded by water filled systems, sequencing of scaffold erection and modification and the impacts of forced oxygenation of the primary coolant using hydrogen peroxide during crud burst. The inspectors discussed with Chemistry and HP personnel the licensee’s use of PRC-01 resin for removal of colloidal cobalt and technologies being considered for future source term reduction such as zinc injection.

Plant collective exposure histories for the years 2000 through 2002, based on the data reported to the NRC pursuant to 10 CFR 20.2206 (c), were reviewed and discussed with licensee staff, as were established goals for reducing collective exposure. In addition, the inspectors examined the dose records of the three declared pregnant workers during 2003 to evaluate current gestation dose. The applicable RP procedure was reviewed to assess controls for declared pregnant workers.

RP program activities and their implementation were evaluated against 10 CFR 19.12; 10 CFR Part 20, Subparts B, C, F, G, H, and J; and approved licensee procedures. In addition, licensee performance was evaluated against Regulatory Guide 8.8, Information Relevant to Ensuring that Occupational Radiation Exposures at Nuclear Power Stations will be As Low As Reasonably Achievable, and Regulatory Guide 8.13, Instruction Concerning Prenatal Radiation Exposure. Procedures and records reviewed within this inspection area are listed in Section 2OS2 of the report Attachment.

Problem Identification and Resolution. Five licensee condition reports associated with ALARA activities were reviewed and assessed. The inspectors evaluated the licensee's ability to identify, characterize, prioritize, and resolve the identified issues in accordance with Procedure 0-ADM-518, "Condition Reports." The documents reviewed are listed in Section 2OS2 of the report Attachment.

b. Findings

No findings of significance were identified.

2PS2 Radioactive Material Processing and Transportation

a. Inspection Scope

Waste Processing and Characterization. During the week of October 6, 2003, the operability and configuration of selected liquid and solid radioactive waste (radwaste) processing systems and equipment were evaluated by the inspectors. Inspection activities included document review, interviews with plant personnel, and direct inspection of processing equipment and piping.

The inspectors directly observed radwaste processing equipment material condition and configuration for liquid and solid radwaste systems during plant tours with the Radwaste Supervisor. Liquid radwaste equipment was inspected for general condition and licensee staff were interviewed regarding equipment function and operability. The following components of the liquid radwaste system were inspected for material condition and for configuration compliance with the UFSAR:

- Waste hold-up tanks, Auxiliary Building
- Waste hold-up tanks, Radwaste Building
- Waste Monitor Tanks
- Portable Liquid Radwaste Purification Filter System
- Laundry and Hot Shower Tanks

The Radwaste supervisor was interviewed to assess knowledge of resin sluicing processes and solid radwaste operations. Procedural guidance involving the transfer of resin and filling of waste packages was reviewed for consistency with the licensee's procedures and Chapter 11 of the UFSAR for system requirements. Documents reviewed by the inspectors are listed in the report Attachment.

Licensee radionuclide characterizations of each major waste stream were evaluated by the inspectors. For dry active waste (DAW), primary resin, secondary resin, and filters, the inspectors evaluated the licensee's procedural guidance against 10 CFR 61.55 and the Branch Technical Position on Radioactive Waste Classification details. Comparison data between the licensee's waste sample gamma-emitter concentrations and those of a vendor laboratory were evaluated by the inspectors for the years 2001 - 2003. The licensee's analysis for, and the use of scaling factors for hard-to-detect nuclides were also assessed by the inspectors. DAW stream radionuclide data were reviewed and discussed with the licensee for the period 2001-2003 to determine if known plant changes had an effect on radionuclide composition and were assessed by the licensee. The inspectors also reviewed waste shipment quantities for processing and burial for the years 2001-2003.

Transportation. The inspectors evaluated the licensee's activities related to the transportation of radioactive material. The evaluation included a review of shipping records and procedures, assessment of worker training and proficiency, and direct observation of shipping activities.

The inspectors assessed eight shipping-related procedures for compliance to applicable regulatory requirements. Selected shipping records were reviewed for consistency with licensee procedures and completeness and accuracy. Training records for two individuals qualified to ship radioactive material were checked for completeness. In addition, training curricula provided to these workers were assessed by the inspectors.

On October 7, 2003, the inspectors observed receipt of five boxes of radioactive material. On October 8, 2003, the inspectors observed the packaging of a shipment of radioactive charcoal filters and interviewed the HPT regarding packaging controls, contamination and radiation controls, and preparation of shipping papers for the shipment. In addition, on October 9, 2003, the inspectors directly observed radiation and contamination surveys of a truck and two radioactive containers being received for entry into the Radiologically Controlled Area.

Transportation program guidance and implementation were reviewed by the inspectors against regulations detailed in 10 CFR 71, and 49 CFR 170-189 and applicable licensee procedures listed in the Attachment to this report. In addition, training activities were assessed by the inspectors against 49 CFR 172 Subpart H, and the guidance documented in NRC Bulletin 79-19.

Problem Identification and Resolution. Licensee condition reports and self-assessments associated with radwaste processing and transportation were reviewed by the inspectors. Three condition reports and two self-assessments reviewed and evaluated during the inspection of this program area are listed in the report Attachment. The inspectors assessed the licensee's ability to identify, characterize, prioritize, and resolve the identified issues in accordance with O-ADM-518, Condition Reports, 4/18/03C.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator (PI) Verification (71151)

.1 Reactor Safety Cornerstone Performance Indicators

a. Inspection Scope

The inspectors sampled licensee submitals for the two performance indicators (PIs) listed below for the period from July 2002 through June 2003. To verify the accuracy of the PI data reported during that period, PI definitions and guidance contained in NEI 99-02, "Regulatory Assessment Indicator Guideline," Revision 2, were used to verify the basis in reporting for each data element.

Reactor Safety Cornerstone

- Safety System Unavailability, Heat Removal System
- Safety System Unavailability, Residual Heat Removal System

The inspectors reviewed a selection of Licensee Event Reports, portions of Unit 3 and Unit 4 operator log entries, daily morning reports (including the daily condition report descriptions), the monthly operating reports, and PI data sheets to verify that the licensee had adequately identified the safety system unavailability during the previous four quarters. This number was compared to the number reported for the PI during the current quarter. In addition, the inspectors also interviewed licensee personnel associated with the PI data collection, evaluation, and distribution.

b. Findings

No findings of significance were identified.

.2 Occupational Radiation Safety Performance Indicator

a. Inspection Scope

The inspectors sampled licensee submittals for the PIs listed below for the period from October 2002 through October 2003. To verify the accuracy of the PI data reported during that period, PI definitions and guidance contained in NEI 99-02, “Regulatory Assessment Indicator Guideline,” Rev. 2, were used to verify the basis in reporting for each data element.

Occupational Radiation Safety Cornerstone

- Occupational Exposure Control Effectiveness PI

Licensee records reviewed included those used by the licensee to identify occurrences of locked HRAs, very HRAs, and unplanned personnel exposures. Additional records reviewed by the inspectors included ALARA records addressing individual exposures. The inspectors also interviewed licensee personnel that were accountable for collecting and evaluating the PI data.

Public Radiation Safety Cornerstone

- RETS/ ODCM Radiological Occurrences PI

Licensee corrective action program records for periodic liquid or gaseous effluent releases were screened for the period October 2002 to October 2003 to see if any met the PI criteria. Screening included keyword searches for the words “release” and “spills”. Personnel responsible for screening, documenting and reporting RETS/ OCDM Radiological Occurrences PI data were interviewed by the inspectors.

b. Findings

No findings of significance were identified.

4OA2 Problem Identification and Resolution

.1 Daily and Annual Sample Review

a. Inspection Scope (71152)

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

Additionally the inspectors selected one deficient condition for detailed review and discussion with the licensee. The condition reports were examined to verify whether problem identification was timely, complete and accurate; safety concerns were properly classified and prioritized for resolution; technical issues were evaluated and dispositioned to address operability and report ability; root cause or apparent cause determinations were sufficiently thorough; extent of condition, generic implications, common causes, and previous history were adequately considered; and appropriate corrective actions (short and long-term) were implemented or planned in a manner consistent with safety and Technical Specification compliance. The inspectors evaluated the condition reports against the requirements of the licensee's corrective action program as delineated in Administrative Procedures 0-ADM-518, "Condition Reports", O-ADM-059 "Root Cause Analysis", and 10 CFR 50, Appendix B. The inspectors reviewed the history of equipment deficiencies associated with the RHR sumps, including:

- CR 00-1236 Both 3A RHR Pump Room Sump Pumps Inoperable
- CR 01-1292 Components in the Room Sumps Found Out of Service (3P25B, LS-3-3509,)
- CR 02-1186 Manual Cycling of RHR Heat Exchanger Room Sump Pump Required to Manually Pump
- CR 02-1499 Failure of 4P26A in the RHR Pump Room is the 2nd Pump Reported Failed
- CR 03-1806 Sump Pump 3P26A in the 3B RHR Pump Room Seized
- CR 03-2297 Unit 4 RHR Sump Pump 4P25A Failed Post Maintenance Test

b. Findings and Observations

No findings of significance were identified.

4OA5 Other Activities

.1 (Closed) NRC Temporary Instruction (TI) 2515/152, Reactor Pressure Vessel Lower Head Penetration Nozzles (NRC Bulletin 2003-02), Rev 1 - Unit 4

a. Inspection Scope

The inspectors observed activities relative to inspection of the reactor vessel head lower head penetration nozzles in response to NRC Bulletin 2003-02. The guidelines for the inspection are provided in NRC TI 2515/152, "Reactor Pressure Vessel (RPV) Lower Head Penetration Nozzle Inspection" (NRC Bulletin 2003-02). As detailed below in section b.A.1 - K.1 per the documentation format requirements of TI 2515/152 Rev 1, the inspectors reviewed licensee activities to verify the absence of boric acid crystals, which may be evidence of a leak in lower head penetration nozzles, and to verify the integrity of the RPV lower head.

Specifically, using NRC IP 57050, "Visual Testing Examination," this inspection included review of visual examination (VT) procedures, assessment of inspection personnel training and qualification, the observation and assessment of VT examinations, and compliance with acceptance criteria. Discussions were held with Framatome-ANP contractor representatives and licensee engineering personnel. Activities were examined to verify that the licensee was meeting its inspection commitments using procedures, equipment, and personnel that have been demonstrated to be effective in detecting signs of leakage from RPV lower head penetration nozzles and the detection of RPV lower head degradation. In addition, this inspection gathered information to help the NRC staff identify possible future regulatory positions and generic communications.

On October 14, 2003, NRC headquarters technical staff, Region II personnel, and the resident inspectors participated in a conference call to discuss the Turkey Point examinations. There were no issues identified concerning the bottom head integrity during the call.

b. Findings and Observations

No significant findings were identified.

TI 2515/152 Rev 1, Reporting Requirement Questions for Visual Examinations:

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

The inspectors found that visual inspections were being performed in accordance with approved and demonstrated procedures with trained and qualified inspection personnel. Personnel performing Nondestructive Examination (NDE) were qualified and certified in accordance with IWA-2300 of the 1989 Edition of ASME Section XI as implemented by CSI-QI-9.1, “NDE Personnel Qualification & Certification Program” and/or the Florida Power & Light (FP&L) approved Framatome (vendor) certification program. In addition to qualification training, VT personnel had additional training on RPV head inspections. All examiners, both licensee and contract personnel, had significant experience, including experience inspecting RPV upper head penetrations. The inspectors verified that operating experience from the South Texas Project Unit 1 examination results were incorporated into the inspectors’ training.

A.2 Was the examination performed in accordance with demonstrated procedures?

Remote and direct visual examinations of the lower head penetrations were conducted in accordance with the following approved documents and demonstrated procedures:

- Framatome-ANP No. 6028887A, “Reactor Head Nozzle Penetration Remote Visual Inspection Plan for Turkey Point Units 3 and 4,” Revision 2, (Incorporated as FPL Procedure VP 03-063)
- Framatome-ANP No. 54-ISI-367-05, “Procedure for Visual Examination for Leakage of Reactor Head Penetrations,” Revision 5
- Turkey Point No. RPVBMI-IP, “Florida Power and Light Reactor Pressure Vessel (RPV) Bottom Mounted Instrumentation (BMI) Penetration Inspection Program for Turkey Point U3 and U4,” Revision 0

- Turkey Point Procedure No. 0-ADM-537 “Boric Acid Corrosion Control Program”

- Turkey Point PTN-ENG-LRAM-00-0028, “Boric Acid Wastage Surveillance Program - License Renewal Basis Document”.

- Turkey Point Drawing No. 117892E “Instrumentation Nozzle Assembly,” Revision 2

The inspection techniques had been previously demonstrated under the Materials Reliability Program Inspection Demonstration as capable of confirming reactor pressure vessel integrity. The Turkey Point Unit 4 RPV lower head has a total of 50 BMI penetrations. Site procedures required a 360 degree examination of all 50 penetrations and bottom head insulation was lowered to provide access for both direct and remote visual examination techniques. A bare metal direct visual inspection was performed for the lower head to ascertain whether any wastage or other anomalies were present. Then BMI penetration examination procedures used a magnetic crawler mounted camera which scanned one quadrant at a time for 41 of the 50 penetrations. Due to cable limitations, 9 penetrations had some areas which could not be examined by the remote crawler. For these areas, a hand-held camera on a long stick was manipulated locally (penetration nos: 16, 17, 23, 25, 26, 28, 30, 35 and 47). In total, 100% of the circumference of each penetration as it entered the RPV lower head was covered with these examinations in accordance with procedures.

The intent of the this portion of the inspection was to evaluate the overall conditions of the reactor BMIs and particularly a view of the interface between the Alloy 600 nozzle and the vessel/weld pad. The inspectors verified that the high-resolution PTZ (pan, tilt, zoom) cameras used to view the reactor had been qualified through performance demonstrations in mock up situations as well as passing resolution VT-1 Lower Case Vision Card (0.044) and lighting checks throughout the inspection in accordance with procedures. The inspectors reviewed the FPL/Framatome procedures, observed in-process examinations of the lower head penetrations, and reviewed digital photographs. Approved acceptance criteria with a zero tolerance critical parameter for RPV leakage was applied in accordance with site procedures.

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

The criteria used at Turkey Point to determine the adequacy of the inspection was the ability to identify evidence of leakage similar to that found at the South Texas BMI penetrations, and upper head penetration leaks identified in the industry. Relevant penetration leakage was described as accumulation of boric acid resembling “popcorn” as defined in EPRI Visual Inspection Guidelines Report No. 1007842 “Visual Examination for Leakage of PWR Reactor Head Penetrations on Top of RPV Head,” Revision 2 of TR-1006296, dated March 2003. All potential leakage and/or crack indications were required to be reported for further inspection and disposition. Based on observation of the inspection process, the inspectors considered that deficiencies would be appropriately identified, dispositioned, and resolved. No evidence of leakage or cracks were identified.

A.4 Was the examination capable of identifying the pressure boundary leakage as described in the bulletin and/or RPV lower head corrosion?

Based upon review of the results for the BMI examination, procedures, qualifications, appropriate lighting, and sensitivity requirements, the inspectors determined that the licensee was capable of identifying pressure boundary leakage, boric acid corrosion and wastage if present.

B. Could small boron deposits representing RCS leakage, as described in NRC Bulletin 2003-02, be identified and characterized if present by the visual examination method used?

The inspectors observed that had boron deposits been present, as described in the bulletin, the licensee could have readily identified and characterized it due to the following:

- Bottom head insulation was lowered, which allowed visual examination of 360 degrees around each BMI penetration nozzle, as requested by NRC Bulletin 2003-02. Robotic crawler mounted cameras were used where possible to allow maximum time for examination and analysis while limiting personnel exposure to meet regulatory ALARA specifications.

- Examinations were performed in accordance with the industry standard EPRI Report 1007842, “Visual Examination for Leakage of PWR Reactor Head Penetrations on Top of RPV Head,” Revision 2 of TR-1006296, dated March 2003, to incorporate all current data from recent industry experience. Direct visual observation of the lower reactor vessel head was performed by the inspectors on October 9, 2003, including digital photographs which were then compared with the licensee’s observations.

- The licensee’s indexing plan (for the camera equipped robotic crawler) ensured that all required areas of every nozzle penetration were inspected.

- With the available lighting on the video inspection equipment and the clarity of the picture, the inspectors observed that the resolution of the video camera provided capability of detecting any debris or small boron deposits on the bare metal head or the annulus area between the penetration and head of each vessel penetration.

- As detailed below, a loose film was noted on the lower head, but was easily removed. The licensee had taken samples from these deposits and concluded that there was no boric acid present. The inspectors reviewed all lower head penetration still photos. For those penetrations that were not easily accessible, the inspectors reviewed the motion video to better evaluate the quadrant. There were no obstructions to preclude a 100% visual inspection of the RPV BMI penetrations. No significant findings were identified.

C. How was the visual inspection conducted (e.g., with video camera or direct visual by the examination personnel)?

A crawler mounted high resolution PTZ camera (Inuktum Nano Magnetic Crawler - 3.6 mm lens - 1/4"CCD-resolution 400 TV lines - 0.5 lux) provided a 360 degree view of the intersection of the bottom head instrument tube and the Alloy 600 weld pad. In cases where the penetrations could not be reached due to configuration, a camera on a long pole was used. Due to the difficulties associated with using remote examination techniques, there were occasions when difficulties were encountered with indexing. Inspectors observed that whenever penetration/quadrant location was questioned, personnel were sent into Containment to verify by direct visual examination the location of the remote camera crawler.

D. How complete was the coverage (e.g., 360 degrees around the circumference of all the nozzles)?

There were no significant items that could impede effective examinations and the licensee was able to inspect 360 degrees around each of the 50 lower head penetration nozzles

E. What was the physical condition of the reactor vessel lower head (e.g., debris, insulation, dirt, deposits from any source, physical layout, viewing obstructions)? Did it appear that there were any boric acid deposits at the interface between the vessel and the penetrations?

The lower head surface had a thin dry film (dustlike) and/or a stain-like residue, around most of the BMI's, and on much of the RPV lower head surface. The film varied in color from mostly white on the Alloy 600 BMI penetrations to a very light orange (rust) on patches of the RPV head surface. The lower vessel head had been originally coated with a metallic paint for corrosion resistance during shipping and there was evidence of localized areas of small flaking paint on the vessel surface and on the surfaces of some of the Alloy 600 weld pads. The film and flaking paint did not obstruct any of the examinations of the BMI nozzle to vessel interface or other areas of the head. No boron deposits were noted by the inspectors on any of the lower pressure vessel surfaces and the inspectors did not see any "popcorn" type boric acid crystals surrounding the penetrations. The inspection results were documented in Condition Report CR 03-0442 and there was no identified wastage, corrosion, or cracks that needed repair. The inspectors observed examinations, reviewed portions of the video of the bottom head inspection to verify the licensee's inspection results, and held discussions with the appropriate engineering and examination personnel.

F. What material deficiencies (i.e., cracks, corrosion, etc.) were identified that required repair?

No significant material deficiencies were identified. As discussed above, there was evidence of small localized areas of small flaking paint. The effects of small amounts of paint flaking/loose coating in the reactor vessel cavity on the Emergency Core Cooling

System (ECCS) were not considered safety significant by the licensee. The licensee's evaluation determined that the paint flakes/loose coating could not migrate to the ECCS sump because of the material density (density of coating would cause it to sink to the bottom of the reactor cavity and therefore be unable to flow to the sump which is at a higher elevation), and because there is no flow in the cavity during operation. Consequently, no follow-up was considered necessary (Condition Report CR 03-0429-02).

G. What, if any, impediments to effective examinations, for each of the visual examinations were identified (e.g., insulation, instrumentation, nozzle distortion)?

No significant items that could impede the examination process were noted during observation of the visual examinations. The licensee was able to inspect 360 degrees around each of the 50 lower head penetration nozzles. However the inspectors noted that in some cases the crawler mounted remote camera viewing angle did not provide an optimum downward looking view of the annulus between the nozzle and the weld pad. This was due to the height (~1/4-inch) of the 4" minimum diameter weld pad buildup around the BMI nozzles, and the short distance that the camera extended from the end of the crawler. This condition was mostly prevalent when approaching the BMI nozzle from the uphill side. Side views and downhill views had an increasingly better viewing angle. This condition although acceptable, was less than the viewing angle observed on the upper head Control Rod Drive Mechanism inspections that do not have a weld pad buildup. However, in all cases the BMI nozzles were viewed 360 degrees as the Alloy 600 nozzle penetrates the Alloy 600 weld pad and RPV lower head surface and the viewing angle was sufficient to determine if leakage occurred.

H. Did the licensee perform appropriate follow-up examinations for indications of boric acid leaks from pressure-retaining components above the RPV lower head?

There were no current indications of boric acid leaks from pressure-retaining components above the RPV lower head.

I. Did the licensee take any chemical samples of the deposits? What type of chemical analysis was performed (e.g., Fourier Transform Infrared (FTIR)), what constituents were looked for (e.g., boron, lithium, specific isotopes), and what were the licensee's criteria for determining any boric acid deposits were not from RCS leakage (e.g., Li-7, ratio of specific isotopes, etc.)?

The lower head surface had a thin dry film, or a stain-like residue, around most of the BMI's, and on much of the RPV lower head surface. Two representative BMI Alloy 600 penetrations (Nos. 43 and 46) were selected due to ease of access for sampling of the white residue. The sampling plan was to swipe the nozzle surface at these locations with clean wet gauze pads, and then scrape off any tightly adhering material. However the swipes cleaned off the residue with light hand pressure and there was nothing left to scrape.

An isotopic analysis was performed of the two smears. The swipe samples were analyzed first for fission and activation products that would indicate operational RCS leakage (Cesium-134 and -137, Cobalt-57 and -60). The swipe sample (residue) was then dissolved in demineralized water and the solution analyzed for lithium (via Atomic Absorbence Spectrophotometer) and boron (via titration and pH testing). Neither lithium or boron was detected. As additional tests identified large amounts of calcium in the solution, it was concluded that the residue on the BMI penetrations and bottom head was not the result of operational RCS leakage.

J. Is the licensee planning on doing any cleaning of the head?

There was no evidence of accumulated boric acid crystals. There was evidence of a light film on the surfaces of the vessel and some of the Alloy 600 weld pads around each nozzle. Analysis revealed that the film was primarily calcium based and not acidic (no boric acid), therefore the licensee did not wash the lower head to remove the light film. No examples of leakage, wastage, or material deficiencies were identified during the visual examinations.

K. What are the licensee's conclusions regarding the origin of any deposits present and what is the licensee's rationale for the conclusions?

The film on the BMIs and on the vessel surface appeared to have flow like characteristics, possibly from prior cavity seal ring leakage or wash down events (The most significant wash down of the vessel head occurred after a conoseal leak in 1987). The flow characteristics of the film are indicative of fluid traveling on the surface at low temperatures (cold shutdown, refueling, etc.) since the stains ran for long distances. There were no deposits with accumulated thickness, which would occur from high temperature leakage, at any location on the RPV lower head.

The overall condition of the Unit 4 RPV lower head (from direct bare metal inspection and during the process of maneuvering the crawler mounted and pole mounted cameras to examine the 50 penetrations), appeared clean with no evidence of leakage from the 50 RPV penetrations or wastage of the RPV head surface. The bottom head metal insulation dome was removed from the head by dropping it down ~14 inches prior to the examination to allow the greatest possible visual access to the head. The inside surface of the insulation adjacent to the head was inspected and found to be relatively clean and free of accumulation of corrosion product or debris. Based on the lack of debris in the insulation dome and the visual observations of the lower head, it was concluded that there was no wastage of the RPV lower head surface.

.2 (Open) NRC Temporary Instruction 2515/150, Reactor Pressure Vessel Head and Head Penetration Nozzles (NRC Bulletin 2002-02) (Unit 4)

a. Inspection Scope

The inspectors observed activities relative to inspection of the reactor pressure vessel head (RPVH) nozzles in response to NRC Bulletins 2001-01, 2002-01, 2002-02 and

NRC Order EA-03-009 Modifying Licenses dated February 11, 2003. The inspection included review of NDE procedures, assessment of NDE personnel training and qualification, and observation and assessment of visual (VT), ultrasonic (UT), and eddy current (ET) examinations. Discussions were also held with contractor representatives and other licensee personnel. The activities were examined to verify licensee compliance with regulatory requirements and gather information to help the NRC staff identify possible further regulatory positions and generic communications. Specifically, the inspectors reviewed or observed the following:

(1) Bare Metal VT Examination

Observed a portion of in-process bare metal remote video VT inspection of RPVH Nozzle Nos. 5, 9,19, 35, 55, 67, 62, 38, 43, 37, 29, 36, 44, 61, 67, 43, 25, 20, 13, 57, 21, 6, 49, 1, 4, 66, 34,18, 8, 3, 7, 14, 6, 2, 26, and vent line nozzle (including surface around the nozzles)

Reviewed a portion of RPVH bare metal VT video results and still digital pictures for Nozzle Nos. 51, 15, 7, 66, 42, 24, 17, 11, 16, 23, 39, 63, 1, 4, 12, 48, 28, 34, 18, 8, 3, 31, 15, 7, 2, 6, 14, 10, 26, 46, and vent line nozzle (including surface around the nozzles)

The inspections were observed/reviewed in order to verify absence of boron crystals indicative of a leak and to verify the integrity of the RPVH.

(2) UT Examination of RPVH Nozzles

Observed a portion of in-process UT scanning of RPVH Nozzle Nos. 47, 51, 46, 55, and 48

Reviewed the UT results for RPVH Nozzle Nos. 53, 47, 51, 46, 55, 48, 18, 30, and vent line nozzle

UT observations/reviews included review of results intended to assess for leakage into the interference fit zone of the nozzles.

(3) ET Examination of the Vent Line Nozzle J-Groove Weld

Observed in-process ET examination of the surface of the vent line nozzle J-groove and reviewed the ET results

The inspectors reviewed and discussed with licensee personnel the susceptibility ranking calculation and the basis for the RPVH temperatures used in the calculation. The basis for RPVH temperature input was reviewed to verify appropriate plant specific information was used in the time-at-temperature model for determining RPVH susceptibility ranking.

The inspectors reviewed licensee procedures and inspection results for visual examinations to identify potential boric acid leaks from pressure-retaining components above the RPVH.

b. Observations and Findings

1) Verification that the examinations were performed by qualified and knowledgeable personnel.

The inspectors found that visual and NDE inspections were being performed in accordance with approved and demonstrated procedures with trained and qualified inspection personnel. All examiners had significant experience, including experience inspecting RPVHs. In addition to qualification to Code requirements, VT and UT personnel had additional training on RPVH inspections.

2) Verification that the examinations were performed in accordance with approved procedures.

The Turkey Point Unit 4 RPVH has 65 Control Rod Drive Mechanism (CRDM) type nozzles and one vent nozzle, for a total of 66 nozzles. The bare head remote visual inspection was performed in accordance with Framatome Procedure 54-ISI-367 and Remote Visual Inspection Plan (Document 6028887A). The procedure used a high-resolution miniaturized camera delivered by a crawler which scanned a portion of each nozzle and surrounding head material with each pass. The scans covered the full circumference at the nozzle-to-top-of-head interface areas of all of the 66 nozzles and surrounding head surfaces. Also, 100% of the head surface outside the nozzle areas was inspected.

All 66 nozzles (65 large nozzles and 1 vent nozzle) received remote mechanized UT examination from the inside surface in accordance with approved Procedures 54-ISI-100-09 (large nozzles) and 54-ISI-137-02(vent line). Procedure 54-ISI-100-09 used a blade probe and the ‘Time of Flight’ technique for CRDM nozzles with sleeves. This technique employed two 5 Mhz, 50 degree L (Longitudinal) transducers with scanning in the vertical direction. For the open-bore large nozzles (12 total), the UT examination employed the ‘time of flight’ technique using two sets (one 30 degree and one 45 degree) of 5 MHz, L (longitudinal) wave transducers with the 30 degree directed in the axial direction and the 45 degree directed in the circumferential direction. In addition, the nozzle volume was scanned using 60 degree, 2.25 MHz, shear wave transducers directed in the axial and circumferential directions and a 0 degree, 5 MHz L Wave transducer. The vent nozzle was scanned with a 0 degree, 5.0 MHz, L wave transducer, a 45 degree, 5.0 MHz, shear wave transducer (axial flaw detection), and a 70 degree, 5.0 MHz, shear wave transducer (circumferential flaw detection). The inspection area extended from a minimum of 2" above the J-groove weld to the bottom of the nozzle. For both procedures an automated UT data acquisition and analysis system (Accusonex) was used.

Since the RPVH vent nozzle did not have an interference fit, the J-groove weld surface was ET examined to assess if leakage had occurred through the J-groove weld. This was performed in accordance with Procedure 54-ISI-460-01 using a 2X9 orthogonal coil array.

The inspectors reviewed the Framatome procedures and inspection plans, and observed in-process examinations as noted above. Approved acceptance criteria and/or critical parameters for RPVH leakage were applied in accordance with the procedures. The licensee identified two conditions where part IV.C.(1)(b)(i), (UT of each RPVH penetration nozzle from two inches above the J-groove weld to the bottom of the nozzle) was not met. The first condition involved penetration #11 where a small area of the non-pressure boundary portion of the penetration at the bottom of the nozzle did not receive full UT coverage due to transducer lift-off. The second condition involved 53 nozzles with sleeves, which required the use of the blade probe UT technique. This limitation resulted because of the design of the blade probe, which uses the "time of flight" technique scanning vertically employing two transducers separated approximately 0.787 inches apart. The area not covered by this technique is ½ the distance between the transducers, approximately 0.39 inches at the bottom of the nozzles. These limitations are documented in FPL Relaxation Request Letter L-2003-272, dated October 21, as supplemented by letters dated October 23 and 31, 2003. The relaxation was approved by NRC Letter, Subject - Turkey Point Unit 4 - Relaxation of the Requirements of Order (EA-03-009) Regarding Reactor Pressure Vessel Head Inspections (TAC NO. MC1082), date October 31, 2003.

3) Verification that the licensee was able to identify, disposition, and resolve deficiencies.

Based on observation of the inspection process, the inspectors considered deficiencies would be appropriately identified, dispositioned and resolved. No cracks, wastage or leakage were identified.

4) Verification that the licensee was capable of identifying the primary water stress corrosion cracking (PWSCC) phenomenon described in the bulletins.

The licensee performed NDE examinations on all of the RPVH nozzles during the outage. The inspection techniques had been previously demonstrated under the MRP Inspection Demonstration Program as capable of detecting PWSCC type cracks as well as cracks from actual samples from another site.

5) Evaluate condition of the reactor vessel head (debris, insulation, dirt, boron from other sources, physical layout, viewing obstructions).

Although some debris was observed, any debris that could have possibly masked indications of leakage or wastage were noted on the inspection report for cleaning and additional inspection. Based on discussion with licensee inspection personnel, all areas of debris which impeded the inspection were easily removed and the areas re-inspected. This allowed 100 percent visual inspection of each of the 66 RPVH nozzles with no significant obstructions impeding the examination.

6) Evaluate ability for small boron deposits, as described in NRC Bulletin 2001-01, to be identified and characterized.

The inspectors observed that the resolution of the video camera provided capability of detecting any debris or small boron deposits on the bare metal head. As noted above there were no obstructions to preclude essentially 100% visual inspection of the RPVH penetrations. As noted above the loose debris noted at the RPVH to nozzle areas that could mask boron deposits, was removed and the area re-inspected.

7) Determine extent of material deficiencies (associated with the concerns identified in the three bulletins) which were identified that required repair.

No evidence of RPVH leakage, wastage or cracking was identified during the visual or NDE examinations.

8) Determine any significant items that could impede effective examinations.

No significant items that could impede the examination process were noted during observation of the visual or NDE examinations. Twelve of the large nozzles and the vent line nozzle were open and thus received and open-bore UT examinations. The CRDM nozzles had sleeves requiring the use of blade probe examinations, which limited the UT coverage as noted in paragraph 2) above.

(9) Determine the basis for the temperatures used in the susceptibility calculation.

The inspectors reviewed the susceptibility calculation and the basis for the RPVH temperatures used in the calculation, as documented in FPL Engineering Evaluations and FPL Letters listed in List of Documents Reviewed (Attachment 1) below. The temperatures used in the susceptibility calculation were based on evaluations and calculations using plant specific fluid temperatures and flow rates. Because of changes in flow rates after steam generator replacement, calculations resulted in a decrease in head temperature. Therefore, the susceptibility calculation used one temperature for the period before steam generator replacement and a lower temperature after steam generator replacement. The effective degradation years used was calculated using effective full power years obtained from plant computer database records.

10) Determine if the methods used for disposition of NDE identified flaws were consistent with NRC flaw evaluation guidance.

As noted above, no NDE flaws were identified.

11) Determine if procedures existed to identify potential boric acid leaks from pressure-retaining components above the RPVH and if the licensee performed proper followup for indications of boric acid leaks.

The licensee had a plant procedure in place to inspect components above the RPVH for leakage each refueling outage. The procedure, 0-OSP-041.26 had been completed by Turkey Point Unit 4 on October 5, 2003, at the beginning of the outage. In addition, as part of the RVH bare metal inspection under contractor Procedure 54-ISI-367-05 and the Visual Inspection Plan, additional inspections for evidence of leakage on top of the insulation and some components above the insulation were performed. The inspectors reviewed the completed plant procedure and observed portions of the contractor's as found inspection above the insulation. No leakage or evidence of leakage was identified by the licensee, the contractors, or the inspectors.

.3 (Open) NRC Temporary Instruction 2515/153, Reactor Containment Sump Blockage (NRC Bulletin 2003-01) - Unit 4

a. Inspection Scope

On November 6, 2003, the inspectors completed the review of the licensee's implementation of compensatory measures for the containment recirculation sumps. The compensatory measures were delineated in the Florida Power and Light Company's response to NRC Bulletin 2003-001, Letter L-2003-201, dated August 8, 2003. Attachment 2 to the letter describes Turkey Point's plant specific response to the Bulletin. The licensee stated in their response letter that the following interim compensatory measures were implemented:

- Procedure ES-1.3, "Transfer to Cold Leg Recirculation" was revised to verify that the ECCS and Containment Spray (CS) System pumps aligned in the recirculation cooling mode are operating properly. If any of the pumps are indicating signs of distress, the operator will be instructed to stop the affected pumps and transition to Procedure ECA-1.1, "Loss of Emergency Coolant Recirculation."
- A training brief was issued to operations personnel to increase awareness of the potential for the containment recirculation sump to become clogged during operation of the ECCS and CS pumps in recirculation-cooling mode. The licensee also committed to cover these topics in operator requalification training that started August 18, 2003.
- Procedure ECA-1.1, "Loss of Emergency Coolant Recirculation" was modified to provide additional injection sources by aligning the opposite unit's Refueling Water Storage Tank and High Head Safety Injection pumps, achieving approximately 3 hours additional injection time.
- Existing licensee procedures on foreign material and debris in containment were revised to incorporate the latest industry guidance contained within NEI 02-01, "Condition Assessment Guidelines," Revision 1.
- The amount of unqualified coatings inside containment (that could potentially affect the building sump) are continuing to be reduced by the licensee during refueling outages, including the Unit 4 refueling outage conducted during October 2003.

The inspectors reviewed the aforementioned activities and associated documents. (These items are not an exhaustive list of all compensatory measures taken by the licensee or reviewed by the inspectors, merely the most significant.) The inspectors also noted that the licensee did not make Emergency Operating Procedure changes in order to increase injection time. In the licensee's response to the Bulletin, these changes were not made because they might "result in conditions that are outside the design basis" and "would introduce a significant opportunity for operator error."

The licensee and the inspectors also performed containment walkdowns to quantify potential debris sources and check for gaps in the sumps' screened flowpath. There were no major obstructions in the containment upstream of the sumps nor observable gaps in the sump screens. Additionally there was not any visible peeling or damaged painting/coatings inside containment that would clog containment sumps during accident conditions. Documents reviewed by the inspectors not mentioned above are referenced in the Attachment to this report. Although, the inspection for NRC Temporary Instruction 2515/153 was performed during this inspection, TI 2515/153 will remain open pending further review and inspection.

b. Findings

No findings of significance were identified.

4OA6 Meetings, including Exit

Exit Meeting Summary

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

4OA7 Licensee-Identified Violation

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

- 10 CFR 20.1902(b) requires that the licensee shall post each high radiation area (HRA) with a conspicuous sign or signs bearing the radiation symbol and the words "CAUTION, HIGH RADIATION AREA" or "DANGER, HIGH RADIATION AREA". Contrary to this, on March 10, 14 and 17, 2003, and October 7 and 21, 2003, HRA boundaries were found to be inadequate. In three of these instances the posting had been defeated by personnel propping open swing gates, sliding signs off to the side or covering them with obstructions. In one case an access to a HRA was created by an unposted ladder. In another case the boundary was partially posted due to missing signs. These events were identified in the licensee's Corrective

Action Program as Condition Reports 03-0593, 03-0693, 03-0740, 03-2986 and 03-3399. This finding is of very low safety significance because it did not involve a very HRA or personnel over-exposure, and there were no excessive or unplanned exposures identified.

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee personnel:

G. Alexander, Inservice Inspection
M. Chambers, System Engineer
M. Cornel, Training Manager
J. Danek, Corporate Health Physicist
J. Johns, Maintenance Rule Coordinator
W. Johns, Security Manager
R. Garrison, Framatome-ANP Vessel Head Outage Manager
W. Heize, In Service Inspection
D. Jennings, Radwaste and Transportation Supervisor
M. Jimenez, HP Technical Supervisor
T. Jones, Site Vice-President
M. Lacal, Operations Manager
T. Miller, Acting Maintenance Manager
A. Montalbano, Inservice Inspection
M. Moore, Health Physics Supervisor
W. Parker, Licensing Manager
M. Pearce, Plant General Manager
W. Prevatt, Work Control Manager
D. Robbins, Inservice Inspection Supervisor
G. Warriner, Quality Assurance Manager
S. Wisla, Acting Radiation Protection Manager
A. Zielonka, Site Engineering Manager

NRC personnel:

K. GreenBates, Resident Inspector
J. Hannah, Acting Senior Resident Inspector
J. Munday, Branch Chief
C. Patterson, Senior Resident Inspector
K. Weaver, Senior Resident Inspector

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened

None

Opened and Closed

05000250, 251/2003005-01	NCV	Failure to Identify and Use an Appropriate Acceptance Criteria for the Mail Oil Pump Internals Clearances and Main Oil Pump Suction Check Valve Leakage. (Section 1R15)
2515/152 (Docket 50-251)	TI	Reactor Pressure Vessel Lower Head Penetration Nozzles(NRC Bulletin 2003-02), Rev 1 (Section 4OA5.1)

Discussed

2515/150 (Docket 50-251)	TI	2515/150, Reactor Pressure Vessel Head and Head Penetration Nozzles (NRC Bulletin 2002-02) (Section 4OA5.2)
2515/153 (Docket 50-251)	TI	Reactor Containment Sump Blockage (NRC Bulletin 2003-01) (Section 4OA5.3)

LIST OF DOCUMENTS REVIEWED

1R01: Adverse Weather
Procedures
3-OP-013, “Instrument Air System”

Condition Reports
CR 00-0041, During EP Critique of Hurricane Floyd EPIP-20106 list of Drain Plugs is ambiguous
CR 00-1704, Missile Shield over Unit 4 CCW Room Removed
CR 02-0010, Water Intrusion during Heavy Rain
CR 03-0092, 3B EDG Lube Oil Immersion Heaters Will Not Keep Lube Temperatures >100°F During Cold Weather
CR 03-0199, 3B EDG Experienced "Apparent" Low Lube Oil Temperatures During the Recent Cold Weather Period
CR 03-0199-1, 3B EDG Experienced "Apparent" Low Lube Oil Temperatures During the Recent Cold Weather
CR 03-0426, Vent Lines of Unit 3 EDG Day Tank Separation Criteria Issue
CR 03-4086, Subsection 5.3 Requires Temporary Heat for the Unit 3 EDG Rooms when Outside Temperature is Less than 55F
CR 03-4098, Temporary Heat for the Unit 3 EDG Rooms

CR 03-4185, 3CM Instrument Air Compressor
CR 03-4271, 3CD Was Started for a Cold Weather Start Test, 3 Minutes Into the Run the Compressor Shut Down for an Indicated Low Compressor Oil Pressure

1R04: Equipment Alignment
Procedures
RAR ADD 9808090-O-02, System Description Fuel Pool Cooling, Purification and Ventilation Sys.
4-OSP–023.1, Diesel Generator Operability Test

Drawings
5614-M-3022, sheets 1-6, Emergency Diesel Engine and Oil System

1R05: Fire Protection
Condition Reports
CR 03-1201, Security Failed to Check Fire Impairment Door.
CR 03-1578, Small Fire in Mulch Outside Main Entrance to NTB

1R06: Flood Protection Measure
Procedures
5610-000-DB-001 Section IX, External Flooding Criteria

Drawing
5610-M-3046, sheet 2, Chemical and Volume Control System Boron Recycle System
5610-M-3012, sheet 2, Service Water System Auxiliary Building Area

Condition Reports
2000-2065, Stoplog SL-4 Does Not Provide Flood Protection

1R07: Biennial Heat Sink Performance
Calculations
PTN-3FSM-90-060, RHR Heat Exchanger 3A Performance Test, Rev. 0
PTN-4FSM-90-046, RHR Heat Exchanger 4B Performance Test, Rev. 0

Condition Reports (Crs)
01-1965, 3A ICW Header Crawl Thru Inspection Results, dated 10/30/01
03-0022, TPCW Isolation Valve POV-3-4882 Leak, dated 02/10/03
03-0997, 3C ICW Experiencing Motor Bearing Noise, Shaft Wobble, and Packing Leakage, dated 04/28/03
03-1441, TPCW Isolation Valve POV-3-4883 Rubber Liner Degradation, dated 07/21/03
03-2408, TPCW Isolation Valve POV-3-4882 Started to Close with No Closure Signal, dated 10/03/03
03-3103, 3B ICW Pump Vibration Analysis Measured a Notable Increase in Shaft Displacement, dated 11/03/03
03-3974, Use of Refurbished ICW Pump Discharge Check Valve, dated 11/26/03

Procedures
0-PMM-019.7, Intake Cooling Water Basket Strainer Cleaning and Inspection, Rev. 08/26/03
0-PMM-030.1, Component Cooling Water Heat Exchanger Cleaning, Rev. 04/21/03
3-OSP-019.4, Component Cooling Water Heat Exchanger Performance Monitoring, Rev. 04/15/02
3-OPS-030.9, Component Cooling Water System Flow Balance, Rev. 08/01/02
4-OSP-030, Component Cooling Water System, Rev. 07/30/01

Performance Tests
0-OSP-062.2, Safety Injection System Inservice Test, completed 08/03/02 and 01/03/02
3-OSP-030.4, Component Cooling Water Heat Exchanger Performance Test, completed 12/03/03
4-OSP-030.4, Component Cooling Water Heat Exchanger Performance Test, completed 12/03/03
4-OSP-030.9, Component Cooling Water System Flow Balance, completed 10/28/03 and 10/29/03
TP-672, Unit 3 Residual Heat Removal Heat Exchanger Performance Test, completed 11/20/90
TP-673, Unit 4 Residual Heat Removal Heat Exchanger Performance Test, completed 11/20/90

Work Orders
WO 33014527-01, 4B CCW HX Tube Cleaning, completed 09/18/03
WO 33014530-01, 4C CCW HX Tube Cleaning, completed 09/25/03
WO 33017423-01, CCW Supply Basket Strainer Cleaning, completed 09/30/03
WO 33018036-01, CCW Supply Basket Strainer Cleaning, completed 10/07/03

Miscellaneous
Unit 3 & 4 Component Cooling Water Heat Exchanger eddy current test results and plugged tubes status, February 2003
JPN-PTN-SENP-95-026, Safety Evaluation for CCW Flow Balance and Post-Accident Alignment Requirements to Support Current and Uprated Conditions, Rev. 3
Unit 3 & 4 ICW Temperature (Limits) Plots, 12/02-10/03
CCW Heat Exchanger Trending for Predicting HX Cleanings, 09/16/03 - 12/31/03
CCW Heat Exchanger Performance Data Trending, 1998-2003
L-90-29, L-91-335, and L-93-74, GL 89-13 Commitment Letters, dated 01/30/90, 01/14/92, and 04/02/93
PTN-ENG-LRAM-00-0031, Intake Cooling Water System Inspection Program - License Renewal Basis Document, Rev. 2
Unit 4B ICW Inspection Report, 10/18-20/03
UFSAR Section 9.3, Auxiliary Coolant System
System Description No. 040, Component Cooling Water (System No. 030), Rev. 09/15/03
System Description No. 165, Intake Cooling Water (System No. 019), Rev. 11/14/02

Technical Requirements Manual
Section 3/4.7.2, Component Cooling Water System
Section 3/4.7.3, Intake Cooling Water System
Section 3/4.7.4, Ultimate Heat Sink

1R08: Inservice Inspection
Procedures

NDE Manual Examination Procedure, NDE - 1.3, Eddy Current Examination of Non-Ferromagnetic Steam Generator Tubing Using Multi-Frequency Techniques, Rev. 13

NDE Manual Examination Procedure, NDE - 2.2, Magnetic Particle Examination, Rev. 9

NDE Manual Examination Procedure, NDE - 4.1, Visual Examination VT-1, Weld/Bolting/Bushings/Washers, Rev. 11

NDE Manual Examination Procedure, NDE - 4.3, Visual Examination VT-3, Rev. 9

NDE Manual Examination Procedure, NDE -5.2, Ultrasonic Examination of Ferritic Piping Welds, Rev. 13
NDE Manual Examination Procedure, NDE - 5.4, Ultrasonic Examination of Austenitic Piping Welds, Rev. 17
NDE Manual Examination Procedure, NDE - 5.16, Ultrasonic Examination Technique For The Detection of Cracking In Feedwater Piping, Rev. 9

Other Documents
Long-Term Flow-Accelerated Corrosion Monitoring Program, ENG-CSI-FAC-100, Rev. 11
Flow-Accelerated Corrosion (FAC) Outage Plan for Turkey Point Unit #4, CSI-FAC-PTN-4-21P, Rev. B
Turkey Point Nuclear Power Plant Unit 4 Inservice Inspection Plan, ISI-PTN-4-Plan, Rev. 3
Third Interval Inservice Inspection Program, ISI-PTN-3/4-Program, Rev. 6
Degradation Assessment for Turkey Point Unit 3 and Turkey Point Unit 4 Steam Generators, Update for the Turkey Point Unit 4 End-of-Cycle 20 Refueling Outage, AES 03024975-1.1, June 2003
Engineering Evaluation, Degradation Assessment for the Turkey Point Units 3 & 4 Steam Generators Update for the Turkey Point Unit 4 EOC-20 Refueling Outage, PTN-ENG-SEMS-03-032
Engineering Evaluation, Justification for Deviation from the EPRI Steam Generator Examination Guidelines for Data Quality Requirements at PTN-4, PTN-ENG-SEMS-03-050
Engineering Evaluation, Justification for Deviation from the EPRI PWR SG Examination Guidelines for Bobbin Coil Voltage Normalization Requirements, PTN-ENG-SEMS-02-061
Letter TPN to NRC, Examination Schedule for Remaining RCS Components, June 20, 2003, TPN Unit 4, Inservice Inspection Program, Third 10-Year Interval, Third Period
Letter NRC to TPN, March 10, 2003, ASME Section XI Relief Request No. 33, Alternate Requirements for Implementation of Appendix VIII, Supplement 10
Letter NRC to TPN, Risk-Informed Inservice Inspection Program
Compliance Matrix for EPRI PWR Steam Generator Examination Guidelines Revision 6, Turkey Point Unit 4, EOC 20 Refueling Outage, October 2003, CSI-NDE-03-074
Framatome ANP Document Identifier 51-5029214-00, Qualified Eddy Current Examination Techniques fro Turkey Point (PTN) Units 3 & 4
ENG/CSI-NDE-99-051,Steam Generators Secondary Side Integrity Plan, Revision 3
CSI-NDE-03-034, Eddy Current Examination Plan for Steam Generator Tubing
Condition Reports: 03-3061, 03-3226, 03-3168, 03-3144, 03-2726, 03-3168, 03-3144, 03-2241, 03-03-0271, 03-2716, 03-2989, 03-1755

Audits/Assessments

QAS-CSI-02-1,	Component, Support & Inspection, Including Steam Generator Protection Program
QRNO-03-0018,	In-Service Inspection and In-Service Testtin
QRNO-02-0140,	Steam Generator Integrity- Primary to Secondary Leak
QRNO-03-007,	Review of PTN-3 Condition Monitoring and Operational Assessment of the Steam Generators Based on Eddy Current Examination, End of Cycle 19, March 2003

1R11: Licensed Operator Requalification

Miscellaneous

Training Scenario Package 760204903, Steam Generator Tube Rupture, Revision 10/17/03
FP&L Nuclear Training Department Information Bulletin #03-31
PTN Nuclear Training Department Attendance Roster for August and September 2003

1R12: Maintenance Rule Implementation

Condition Reports

CR 03-2174, ‘B’ Auxiliary Feedwater Pump Low Oil Pressure Event
CR 03-4169, Failed ‘C’ AFW PMT due to debris in oil after corrective action completion of tubing modifications, overhaul of the MOP.
CR 03-2396, Arms Channel 12 Reading E0011 With Fail Light Lit
CR 03-2783, No Annun Reflash with Arms Channel Failed
CR 00-2213, Arms Channel 5 Alarming During Fuel Movement

Miscellaneous

‘B’ AFW Pump Turbine Loss of Lube Oil Pressure Summary submitted on September 10, 2003

1R15: Operability Evaluations

Condition Reports

CR 03-2095, ‘B’ Auxiliary Feedwater Pump Lube Oil Foot Valve Damage
CR 03-2342, Maintenance Dept. Performed Unauthorized Modifications to AFW
CR 03-2360, Comer. Grade Dedication Package Did Not Identify Critical Dimension
CR 03-2417, Apparent Ineffectiveness of the PTN Corrective Action Program
CR 03-2552, AFW Main Oil Pump Suction Line Found Empty of Oil
CR 03-2850, Steam Flashing/Fluid Hammer Sounds from AFW System
CR 03-3177, Reactor Head Shroud Lifted Prior to Removing the Vent Valve Support

1R16: Operator Work Around

Procedures

ODI-CO-016, Control Room Deficiency Log, Annunciator Status Log and Operator Workarounds

Miscellaneous

Operator Workaround Summary List dated November 5, 2003

1R20: Refueling and Outage Activities

Procedures

4-GOP-103, Power Operation to Hot Standby
4-GOP-305, Hot Standby to Cold Shutdown
4-GOP-503, Cold Shutdown to Hot Standby
4-ADM-200, Conduct of Operations
4-OP-041.7, Draining the Reactor Coolant System

Miscellaneous

Shift Technical Advisor Daily Reports

4OA5: Other Activities

Procedures

SPEC-C-034, Protective Coatings for Service Level 1 Applications Inside Reactor Containment Buildings
0-SMM-050.1, Containment Recirc Sump Screen Inspection
0-SMM-051.3, Containment Closeout Inspection

Miscellaneous

Digital Video Disks of Turkey Point Unit 4 Reactor Vessel Penetrations dated October 2003

Drawings

5613-M-3094, sheet 1, Containment Post Accident Evaluation System
2003-3546, Walkdown of Unit 4 Containment Post-LOCA Flow Paths
2003-3129, Walkdown of Unit 4 Containment Post-LOCA Flow Paths - Section 4OA5

Drawing

5610-M-3046, sheet 2, Chemical and Volume Control System Boron Recycle System
5610-M-3012, sheet 2, Service Water System Auxiliary Building Area

Condition Reports

CR 03-3523, Unit 4 Containment As-Left Coating Condition

Framatome Reactor Vessel Head Inspection Work Scope, Reactor Vessel Head Penetration Inspection Schedule, and Examination Scan Plan

Framatome Document 6028887 Reactor Head Nozzle Penetration Remote Visual Inspection Plan For Turkey Point Unit 3 and 4, Revision 02

Framatome ANP Nondestructive Examination Procedure 54-ISI-367-05, Procedure for Visual Examination for Leakage of Reactor Head Penetrations, Revision 5

Framatome NDE 108.0, Task Lesson Plan Bare Head Inspection, Revision 1

Framatome ANP Nondestructive Examination Procedure 54-ISI-100-09, Remote Ultrasonic Examination of Reactor Head Penetrations, Revision 09

Framatome ANP Nondestructive Examination Procedure 54-ISI-137-02, Remote Ultrasonic

Examination of Reactor Vessel Head Vent Line Penetrations, Revision 02

Framatome ANP Nondestructive Examination Procedure 54-ISI-460-01, Revision 1, Multifrequency Eddy Current Examination of Nozzle Welds and Regions

FPL Letter FPL-2002-061, St. Lucie Units 1 and 2, Turkey Point Units 3 and 4, Response to NRC Bulletin 2002-001, Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity, dated April 3, 2002

FPL Letter FPL-2003-007, NRC Bulletin 2002-01, Request for Additional Information Response, dated January 31, 2003

FPL Letter No. L-2003-272, Turkey point Unit 4 Order (EA-03-009) Relaxation Request, Examination Coverage of Reactor Pressure Vessel Head Penetration Nozzles

Turkey Point Nuclear Plant Procedure 0-OSP-041.26, 5/27/03, Containment Visual Leak Inspection

Personnel Certification Records for Framatome Inspection Personnel, including:

- Framatome Personnel Training Attendance Records
- Turkey Point 4(EOC20) Bare Head Inspection, CRDM Nozzle Inspection W/SUMO-ROCKY BUT Training Matrix dated 10/6-10/25/2003
- Individual Examiner Certification, Training, and Eye Test Records for 6 NDE Examiners

Framatome Equipment Certification Records for the following Inspection Equipment

- μTOMOSCAN Pulser-Receivers VH-8168 and VH-8169
- UT Head Assemblies, including transducers, 7500102, 7500111, 7500112, and 7500537
- UT Blade Probes S0580CN, S0581CN, S0583CN, S0584CN, S0588CN, and S0590CN
- A Sample of UT Transducer Certifications
- ET Calibration Standards 5024264
- ET RD TECH System VH-8726
- ET Probe E34201811

FPL Letter L-2002-185, St. Lucie Units 1 and 2, Turkey Point Units 3 and 4, Response to NRC Bulletin 2002-02, Reactor Pressure Vessel Head Penetration Nozzle Inspection Programs
MRP 48 (PWR Materials Reliability Program)

PTN-ENG-SESJ-02-041, Engineering Evaluation For Response to NRC Bulletin 2002-02 for Turkey Point Units 3 and 4, Revision 0

PTN-ENG-SESJ-01-058, Engineering Evaluation Response to the NRC Bulletin 2001-01 for Turkey Point Units 1 and 2, Revision 0

PTN-ENG-SEFJ-021, Engineering Evaluation Input for The Reactor Vessel Temperature Analysis, Revision 1

Westinghouse WCAP-13493, Reactor Vessel Closure Head Penetration Key Parameters Comparison

Westinghouse Letter FPL-01-131, Florida Power & Light Company Turkey Point Unit 3 Upper head Fluid Temperature Evaluation

Spread Sheet Calculation for Effective Degradation Years (EDY)

Effective Full Power Hours Table

LIST OF ACRONYMS

AFW	Auxiliary Feedwater
ARMS	Area Radiation Monitoring System
ASME	American Society of Mechanical Engineers
BMI	Bottom Mounted Instrumentation
CCW	Component Cooling Water System
CR	Corrective Action Condition Report
CS	Containment Spray System
DAW	Dry Active Waste
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EPRI	Electric Power Research Institute
ET	Eddy Current Examination
FPL	Florida Power & Light
gpm	gallon per minute
HHSI	High Head Safety Injection
HP	Health Physics
HPT	Health Physics Technician
HRA	High Radiation Area
HX	Heat Exchanger
ICW	Intermediate Cooling Water
MOP	Main Oil Pump
NCV	Non-cited Violation
NDE	Nondestructive Examination
NRC	Nuclear Regulatory Commission
PI	Performance Indicator
PMT	Post Maintenance Test
psig	pounds per square inch
PTZ Camera	Pan,Tilt, Zoom Camera
PWR	Pressurized Water Reactor
PWSCC	Primary Water Stress Corrosion Cracking
RCS	Reactor Coolant Systems
RHR	Residual Heat Removal
RP	Radiation Program
RPV	Reactor Pressure Vessel
RPVH	Reactor pressure vessel Head
RWP	Radiation Work Permit
SDP	Significance Determination Process
TI	Temporary Instruction
TPCW	Turbine Plant Cooling Water

TS	Technical Specification
TSA	Temporary System Alteration
UFSAR	Updated Finial Safety Analysis Report
UT	Ultrasonic Examination
VT	Visual Examination