UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
SAM NUNN ATLANTA FEDERAL CENTER
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ATLANTA, GEORGIA 30303-8931

January 30, 2006

Virginia Electric and Power Company
ATTN.: Mr. David A. Christian
Sr. Vice President and
Chief Nuclear Officer
Innsbrook Technical Center - 2SW
5000 Dominion Boulevard
Glen Allen, VA 23060-6711

SUBJECT: NORTH ANNA POWER STATION - NRC INTEGRATED INSPECTION REPORT NOS. 05000338/2005005 AND 05000339/2005005

Dear Mr. Christian:

On December 31, 2005, the United States Nuclear Regulatory Commission (NRC) completed an inspection at your North Anna Power Station, Units 1 and 2. The enclosed integrated inspection report documents the inspection findings, which were discussed on January 11, 2006, with Mr. Jack Davis and other members of your staff.

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

Based upon the results of this inspection, four NRC-identified and one self-revealing findings of very low safety significance (Green) were identified. The findings were determined to involve violations of NRC requirements. However, because of the very low safety significance and because the violations were entered into your corrective action program, the NRC is treating the findings as non-cited violations (NCV) consistent with Section VI.A of the NRC Enforcement Policy. Additionally, three licensee-identified violations which were determined to be of very low safety significance (Green) are listed in Section 4OA7 of this report. If you contest any non-cited violation 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 United States Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, D.C. 20555-0001; with copies to the Regional Administrator, Region II; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, D.C. 20555-0001; and the NRC Resident Inspector at the North Anna Power Station.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response, if any, will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Kerry D. Landis, Chief
Reactor Projects Branch 5
Division of Reactor Projects

Docket Nos.: 50-338, 50-339
License Nos.: NPF-4, NPF-7

Enclosure: Integrated Inspection Report 05000338/2005005 and 05000339/2005005
w/Attachment: Supplemental Information

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U. S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket Nos.:	50-338, 50-339
License Nos.:	NPF-4, NPF-7
Report Nos.:	05000338/2005005, 05000339/2005005
Licensee:	Virginia Electric and Power Company (VEPCO)
Facilities:	North Anna Power Station, Units 1 & 2
Location:	1022 Haley Drive Mineral, Virginia 23117
Dates:	October 1, 2005 - December 31, 2005
Inspectors:	J. Reece, Senior Resident Inspector G. Wilson, Resident Inspector S. Vias, Senior Reactor Inspector, Sections 1R08, 4OA4, 4OA5, 4OA6 J. Fuller, Reactor Inspector, Sections 1R08, 4OA4, 4OA5, 4OA6 T. Nazario, Reactor Inspector, Sections 1R08, 4OA4, 4OA5, 4OA6 E. Michel, Reactor Inspector, Sections 1R08, 4OA4, 4OA5, 4OA6 R. Chou, Reactor Inspector, Sections 4OA3, 4OA7
Approved by:	K. Landis, Chief, Reactor Projects Branch 5 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000338/2005-005, IR 05000339/2005-005; 10/01/2005 - 12/31/2005; North Anna Power Station Units 1 & 2. Routine Integrated Resident and Regional Report. Inservice Inspection.

The report covered a three-month period of inspection by the resident inspectors, senior reactor inspectors and reactor inspectors from the region. Four NRC-identified and one self-revealing findings of very low safety significance (Green) were identified. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609, “Significance Determination Process” (SDP). Findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review. The NRC’s program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, “Reactor Oversight Process,” Revision 3, dated July 2000.

A. NRC-Identified and Self-Revealing Findings

Cornerstone: Initiating Events

Green. The inspectors identified a non-cited violation of 10 CFR 50, Appendix B, Criterion V, Instructions, Procedures and Drawings. Licensee activities affecting quality were not accomplished in accordance with site procedures NASES-6.23 and DNAP-1004, in that the licensee failed to identify multiple boric acid leaks. These procedures require plant personnel to identify and document all evidence of boric acid leakage and complete a formal engineering evaluation for boric acid leaks that meet a defined severity threshold. The licensee immediately entered the leaks into their corrective action system, and conducted an initial operability review prior to unit restart.

This finding is greater than minor because it affected the equipment performance attribute of the Initiating Events Cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. This finding is similar to non-minor example 4.a of IMC 0609 Appendix E, in that the licensee routinely failed to follow procedures by not identifying locations of boric acid leakage. This finding was determined to be of very low safety significance based on the IMC 0609, Appendix A, Phase 1 SDP worksheet. The finding screened as Green because leakage of boric acid is characterized as a Loss of Coolant Accident (LOCA) initiator, but the identified leakage did not contribute to the increased likelihood of a primary or secondary LOCA, and the finding did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions will not be available. The cause of the finding is related to the cross-cutting area of human performance. (Section 1R08.2)

Green. The inspectors identified a non-cited violation of 10 CFR 50.65 (a)(4) which requires that the licensee assess and manage the increase in risk that may result from the proposed maintenance activities. During the removal of scaffolding beneath conductors associated with ‘C’ Reserve Station Service Transformer a section of scaffolding contacted a lightning arrestor connected to the ‘B’ phase conductor. The resultant arc and impending relay actuation increased the risk for a loss of normal power to a 4160V safety-related bus on each unit. The licensee entered this problem into their corrective action program following the inspectors review of the licensee’s root cause evaluation which failed to address the risk assessment aspects of this event.

This finding is more than minor because the licensee risk assessment failed to consider maintenance activities that could increase the likelihood of initiating events. The inspectors determined that the finding is of very low safety significance, Green, since the incremental core damage probability deficit was less than 1E-6 and a loss of normal power to a safety-related bus did not occur. This finding impacts the cross-cutting area of human performance. (Section 1R13.2)

Cornerstone: Mitigating Systems

Green. The inspectors identified a non-cited violation of 10 CFR 50.65 (a)(4) which requires that the licensee assess and manage the increase in risk that may result from the proposed maintenance activities. Upon achieving a reactor defueled plant condition, the licensee failed to continue risk assessments during system alignments and maintenance activities associated with power supplies for the spent fuel cooling pumps. The licensee resumed the risk assessments and entered the deficiency into their corrective action program after identification of the finding by the inspectors.

The licensee’s failure to perform risk assessments is more than minor because it impacted the Mitigating Systems Cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences to the reactor core and the associated cornerstone attribute of human performance. The finding did not increase the likelihood of a loss of offsite power or degrade the licensee’s ability to cope with a loss of offsite power due to actual component failures, resulting in the characterization of very low safety significance (Green). The cause of the finding impacts the cross-cutting area of human performance. (Section 1R13.1)

Green. The inspectors identified a non-cited violation of 10 CFR 50, Appendix B, Criterion XVI, which requires in part that measures shall be established to assure that conditions adverse to quality, such as deficiencies, are promptly identified and corrected. During a containment closeout inspection for the refueling outage on Unit 2, an appreciable amount of small debris was found beneath the seismic support plates in all 3 loop rooms and beneath the air recirculation fans. The licensee took immediate action to remove the debris prior to entering Mode 4 and entered the problem into their corrective action program.

The inspectors determined the finding is more than minor because it could be reasonably viewed as a precursor to a significant event involving debris accumulation on the containment sump screens and a subsequent impairment to suction flow for emergency core cooling system pumps. The inspectors further determined the finding was of very low safety significance and impacted the Mitigating Systems Cornerstone. However, the finding did not result in a loss of function per Generic Letter 91-18, did not represent an actual loss of safety function, and was not potentially risk significant due to possible external events. This finding impacts the cross-cutting area of problem identification and resolution. (Section 1R20.1)

Green. A self-revealing non-cited violation was identified of 10 CFR 50 Appendix B, Criterion V, which requires in part that activities affecting quality shall be prescribed by documented procedures of a type appropriate to the circumstances and shall be accomplished in accordance with these procedures. As a result of the licensee's failure to establish an adequate procedure to control placards affixed to safety-related equipment, a trip of the 2-III Vital Bus Inverter occurred. The licensee has entered this problem into their corrective action program to determine appropriate corrective actions.

The finding was more than minor due to the impact on the Mitigating Systems Cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences and its attribute of procedure quality. The inspectors determined that no additional qualitative assessment was warranted based on the continued availability of core cooling, and the finding resulted in the characterization of Green (very low safety significance). The cause of this finding involved the cross-cutting area of human performance. (Section 1R20.2)

B. Licensee-Identified Violations

Three violations of very low safety significance were identified by the licensee, and have been reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into the licensee's corrective action program. These violations and corrective action tracking numbers are listed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status

Unit 1 began the inspection period at 100 percent power, and remained at or near 100 percent power for the entire reporting period except for minor power reductions to perform required periodic maintenance or testing.

Unit 2 began the inspection period with a power reduction for a planned refueling outage which lasted from October 2, 2005 through October 31, 2005. The unit returned to power and remained at or near 100% power for the remainder of the reporting period except for minor power reductions to perform required periodic maintenance or testing.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity

1R01 Adverse Weather

a. Inspection Scope

The inspectors reviewed the licensee's correction action data base for cold weather related issues and the licensee's adverse weather preparations for cold weather operations which were specified in 0-GOP-4.2, "Extreme Cold Weather Operations," 0-GOP-4.2A, "Extreme Cold Weather Daily Checks." The inspectors walked down the four risk-significant areas listed below to verify compliance with the procedural requirements and to verify that the specified actions provided the necessary protection for the structures, systems, or components. Other documents reviewed are listed in the Attachment to this report.

- Unit 1 & 2 Service Water (SW) pump structure;
- Unit 1 & 2 Emergency Diesel Generators
- Unit 1 & 2 Auxiliary Feedwater Pump House; and,
- Unit 1 & 2 Refueling Water Storage Tanks (RWST) level transmitters.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment

a. Inspection Scope

The inspectors conducted three equipment alignment partial walkdowns to evaluate the operability of selected redundant trains or backup systems, listed below, with the other train or system inoperable or out of service. The inspectors reviewed the functional system descriptions, Updated Final Safety Analysis Report (UFSAR), system operating procedures, and Technical Specifications (TS) to determine correct system lineups for the current plant conditions. The inspectors performed walkdowns of the systems to verify that critical components were properly aligned and to identify any discrepancies which could affect operability of the redundant train or backup system.

- Unit 1 Low Head Safety Injection (LHSI) "B" Train, while Unit 1 "A" LHSI was inoperable due to unplanned work on suction piping weld leak;
- Unit 2 Emergency Diesel Generator (EDG) 2H while the 2J EDG was inoperable due to emergent work on exhaust manifold gasket leaks; and,
- Unit 2 2J EDG while 2H EDG was inoperable due to emergent work to repair a fuel oil leak.

b. Findings

No findings of significance were identified.

1R05 Fire Protection

a. Inspection Scope

The inspectors conducted tours of the eleven areas listed below and important to reactor safety to verify the licensee's implementation of fire protection requirements as described in Virginia Power Administrative Procedure (VPAP)-2401, "Fire Protection Program." The inspectors evaluated, as appropriate, conditions related to: (1) licensee control of transient combustibles and ignition sources; (2) the material condition, operational status, and operational lineup of fire protection systems, equipment, and features; and (3) the fire barriers used to prevent fire damage or fire propagation.

- Main Steam Valve House Unit 2 (fire zone 17-2a / MSVH-2);
- Motor Generator Set House Unit 2 (fire zone Z-27-2 / MGSH-2);
- Turbine Building (includes Chiller Rooms and Z-21B, Z-21C, Z-22, Z-34, Z-35, Z-36, and Z-46B) (fire zone 8-a / TB);
- Motor Generator Set House Unit 1 (fire zone Z-27-1 / MGSH-1);
- Containment Unit 2 (fire zone 1-2a / RC-2);
- Normal Switchgear Room Unit 1 (fire zone 5-1 / NSR-1);
- Normal Switchgear Room Unit 2 (fire zone 5-2 / NSR-2);
- Auxiliary Service Water Pump House (fire zone 13a / ASWPH);
- Post-Accident Recombiner Vault (fire zone 38 / PARV);
- Service Water Valve House (fire zone 48a / SWVH); and,
- Alternate AC Building (fire zone Z-52 / AAC).

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection (ISI) Activities

.1 Piping Systems ISI

a. Inspection Scope

From October 11-14, 2005, the inspectors reviewed the implementation of the licensee's Inservice Inspection (ISI) program for monitoring degradation of the reactor coolant system boundary and the risk significant piping system boundaries for Unit 2. The inspectors selected a sample of American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section XI required examinations and code components in order of risk priority as identified in Section 71111.08-03 of inspection procedure 71111.08, "Inservice Inspection Activities," based upon the ISI activities available for review during the onsite inspection period.

The inspectors conducted an on-site review of nondestructive examination (NDE) activities to evaluate compliance with TS, ASME Section XI, and ASME Section V requirements, 1995 Edition through 1996 Addenda, and to verify that indications and defects (if present) were appropriately evaluated and dispositioned in accordance with the requirements of ASME Section XI, IWB-3000 or IWC-3000 acceptance standards. Qualification and certification records for examiners, inspection equipment, and consumables along with the applicable NDE procedures for the above ISI examination activities were reviewed and compared to requirements stated in ASME Section V and Section XI. Documents reviewed and examinations observed are listed in the Attachment to this report.

Pressure Boundary welding activities associated with ASME Class 2 components were reviewed to verify the welding process and examinations were performed in accordance with the ASME Code Sections III, V, IX, and XI requirements. The inspectors reviewed weld data sheets, the welding procedure specification (WPS), supporting welding procedure qualification records (PQR), welder qualification records, and preservice examination (PSI) results for the weld on 12"-SI-215-153A-Q2, Weld #SW-37, 12" elbow to pipe weld, ASME Class 2, and associated weld repairs and subsequent repair welds.

The inspectors performed a review of piping system and Steam Generator related problems that were identified by the licensee and entered into the corrective action program. The inspectors reviewed these corrective action documents to confirm that the licensee had appropriately described the scope of the problems. Additionally, the inspectors' review included confirmation that the licensee had an adequate threshold for identifying issues, and had implemented effective corrective actions. Through interviews with licensee staff and review of plant issue documents, the inspectors evaluated the threshold for identifying lessons learned from industry issues related to ASME Section XI. The inspectors performed these reviews to ensure compliance with 10CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requirements. The corrective action documents reviewed by the inspectors are listed in the Attachment to this report.

b. Findings

No findings of significance were identified.

.2 Boric Acid Corrosion Control (BACC) ISI

a. Inspection Scope

From October 11, 2005, through October 14, 2005, the inspectors reviewed the licensee's Boric Acid Corrosion Control Program (BACCP) to ensure compliance with commitments made in response to NRC Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary," and NRC Bulletin 2002-01, "Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity."

The inspectors conducted an on-site record review and two independent walk-downs of the reactor building, which is not normally accessible during at-power operations to evaluate compliance with licensee BACCP requirements and 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requirements. In particular, the inspectors verified that licensee visual examinations focused on locations where boric acid leaks can cause degradation of safety significant components and that degraded or non-conforming conditions were properly identified in the licensee's corrective action system.

The inspectors reviewed a sample of engineering evaluations completed for boric acid found on reactor coolant system piping and other ASME code class components to verify that the minimum design code required section thickness had been maintained for any affected component(s). The inspectors also reviewed licencee corrective actions implemented for evidence of boric acid leakage to confirm that they were consistent with requirements of Section XI of the ASME Code, 10 CFR 50 Appendix B, Criterion XVI, and licensee BACCP procedures. Specifically, the inspectors reviewed:

- Plant Issue N-2005-1903-E1, 1-RP-P-1B "B" Refueling Purification Pump;
- Plant Issue N-2004-2622-E1, Boric Acid evaluation for evaluation of potential boric acid exposure of floor stanchion supports, embedded bolts and similar structures; and,
- Plant Issue N-2005-4384-E1, Boric Acid Corrosion Evaluation for NRC identified locations of Boric Acid Leakage (this evaluation is the preliminary, operability evaluation required prior to system start-up).

b. Findings

Introduction: A Green inspector-identified NCV was identified for the failure to comply with 10 CFR 50, Appendix B, Criterion V, Instructions, Procedures and Drawings. As a result of plant personnel routinely failing to follow BACCP procedures and human performance issues, ten boric acid leaks were not identified by the licensee.

Three of these leaks met the licensee's severity threshold for requiring an engineering evaluation prior to unit startup. Licensee procedure DNAP-1004, "Boric Acid Corrosion Control Program," requires that all boric acid leakage must be initially reported in the site corrective action system.

Description: On Wednesday, October 12, 2005, and Thursday, October 13, 2005, the NRC inspectors conducted independent boric acid walk-downs of the Unit 2 reactor building, and observed ten locations of boric acid leakage that the licensee had not previously identified. The licensee had made numerous containment entries and had completed their formal boric acid inspection walk-downs prior to the inspectors' walk-down. Three of these locations of boric acid leakage were considered to be above the severity threshold that required an engineering evaluation, as described in licensee procedure DNAP-1004. Licensee procedure DNAP-1004 requires that all boric acid leakage must be initially reported in the site corrective action system, and that an engineering evaluation is to be completed by qualified boric acid corrosion evaluators for leaks that meet a defined severity threshold. The three boric acid leaks that met the threshold included the following: 1) 2-SI-155 (1B Accumulator Make-Up Header Inlet Isolation Valve) - white, dry boric acid that is contact with valve bolting material and may be greater than ½ inch thick accumulation, 2) 2-SI-157 (1B SI Accumulator 2-SI-LT-2926 Lower Isolation Valve) - small amount of discolored boric acid at bolted connection, 3) 2-CH-357 (1C Reactor Coolant Pump Seal Injection Header Drain Valve) - white, dry boric acid that has greater than ½ inch accumulation. The remaining seven locations were considered to be below maintenance threshold, and did not require additional evaluation, but were required to be documented and cleaned. Licensee operations personnel failed to initiate a corrective action item when a "Danger Do NOT Operate" tag was hung on valve 2-SI-155 (1B Accumulator Make-Up Header Inlet Isolation Valve), and evidence of boric acid leakage was visible on the valve. Licensee procedure DNAP-1004 is a safety related procedure that requires all station personnel to initiate a plant issue when boric acid leakage is observed.

The licensee issued Plant Issue –2005-4571 for the performance deficiency identified by the inspectors. Although the licensee failed to follow their BACCP requirements, the licensee's initial operability screen, for the inspector-identified locations of boric acid leakage, determined that identified components would have performed their intended functions and would not have failed during the next operating cycle if left uncorrected.

Analysis: The performance deficiency associated with this inspector-identified NCV was that licensee activities affecting quality were not accomplished in accordance with site procedures NASES-6.23 and DNAP-1004, in that the licensee failed to identify multiple boric acid leaks, three of which required formal engineering evaluations. These examples should have been prevented and were reasonably within the licensee's ability to foresee, identify, and correct.

This performance deficiency resulted in a finding that is more than minor because it affected the equipment performance attribute of the Reactor Safety/Initiating Events Cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations.

This finding is similar to non-minor example 4.a of IMC 0609 Appendix E, in that the licensee routinely failed to follow procedures by not identifying ten locations of boric acid leakage. Furthermore, failure to identify and evaluate boric acid leaks, if left uncorrected, could become a more significant safety concern, in that, a Loss of Coolant Accident (LOCA) initiator could go undetected.

This finding was determined to be of very low safety significance based on the IMC 0609, Appendix A, Phase 1 Significance Determination Process (SDP) worksheet. The finding is associated with the initiating event cornerstone and screened as Green. Leakage of boric acid is characterized as a LOCA initiator. However, the specific boric acid leaks did not contribute to the increased likelihood of a primary or secondary LOCA, and the finding did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions will not be available.

The inspectors determined this finding involved a human performance cross-cutting aspect, in that, personnel lacked attention to detail by not following procedures to identify and document locations of boric acid leakage. Although the licensee's procedures appropriately described the BACCP's requirement that all plant personnel are to report any unmarked locations of boric acid leakage to their supervisor, multiple boric acid leaks were not properly identified and documented by neither maintenance nor engineering.

Enforcement: 10CFR50, Appendix B, Criterion V, requires, in part, that activities affecting quality shall be prescribed by documented instructions, procedures, and drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings. The licensee implements this requirements, in part, with procedure DNAP-1004 which states that all boric acid leakage must be initially reported using a corrective action item entered into the station corrective action program. Contrary to the above, on October 13, 2005, it was determined that licensee failed to follow BACCP requirements as stated in licensee procedure DNAP-1004, in that locations of boric acid leakage were not identified and documented in the licensee's corrective action program.

This violation is associated with an inspection finding that is characterized by the SDP as having very low risk significance (Green) and is in the licensee's corrective action program as Plant Issue –2005-4384. This violation is being treated as a Non-Cited Violation (NCV), consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000339/2005005-01, Failure to Identify Locations of Boric Acid Leakage.

.3 Steam Generator (SG) Tube ISI

a. Inspection Scope

From October 11, 2005, through October 14, 2005, the inspectors reviewed the Unit 2 SG tube eddy current testing (ECT) examination activities to ensure compliance with TS, applicable industry guidance, and the ASME Code Section XI requirements.

The inspectors reviewed licensee SG inspection activities to ensure that ECT inspections conducted this outage conformed to the North Anna SG Monitoring and Inspection Program plan. The inspectors reviewed the SG examination scope, ECT acquisition procedures, Examination Technique Specification Sheets (ETSS), ECT analysis procedures, the SG pre-outage assessment, and the SG Operational Assessment. The inspectors reviewed documentation to ensure that the ECT probes and equipment configurations used to acquire ECT data from the SG tubes were qualified to detect the expected types of SG tube degradation in accordance with Appendix H, "Performance Demonstration for Eddy Current Examination" of EPRI "Pressurized Water Reactor Steam Generator Examination Guidelines: Revision 6." Additionally, the inspectors reviewed the qualification and certification records for the ASME calibrated ECT standards, computerized data screening sort logic, and ECT data analysis and resolution analysis personnel.

The inspectors reviewed the ECT examination scope for this outage to verify that the examinations could identify potential tube degradation mechanisms. Additionally, the inspectors reviewed the SG tube ECT examination scope to determine that it was consistent with that recommended in EPRI "Pressurized Water Reactor Steam Generator Examination Guidelines: Revision 6" and included tube areas which represent ECT challenges such as the tubesheet regions, expansion transitions and support plates.

The inspectors observed a sample of the post sludge lance visual inspection examination activities to ensure that loose parts, if present, could have been detected.

b. Findings

No findings of significance were identified.

.4 Vessel Upper Head Penetration

a. Inspection Scope

The inspectors reviewed activities performed to ensure licensee compliance with the requirements of NRC Order EA-03-009. The inspectors reviewed the scope of the licensee's activities as they relate to examination of the pressure retaining components above the Reactor Pressure Vessel Head (RPVH) to ensure that all possible sources of boric acid leakage were included, that the examination would be effective in identifying boric acid leakage in this area, and that appropriate actions would be implemented should boron deposits be identified on the RPVH or related insulation. The inspectors verified that the licensee was not required to conduct visual or non-visual NDE of the RPVH this outage.

The inspectors reviewed Plant Issue –2005-3924, which documented that boric acid leakage was identified below a thermocouple connection above the RPVH. The inspectors reviewed the scope of the inspection, the corrective actions performed to remove the boric acid, the evaluation for all locations that the boric acid came in contact with, and the actions to prevent re-occurrence of the leak.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification Program

a. Inspection Scope

The inspectors observed an annual licensed operator requalification simulator examination on November 15, 2005. The scenario, Simulator Examination Guide SXG-56, involved a loss of instrument air, followed by increased primary plant leakage, a loss of bearing cooling pumps with subsequent reactor trip, and a small break loss of cooling accident (LOCA). While this scenario is similar to that used for the previous quarter's requalification inspection, a different operations shift crew was observed. This was a training scenario and did not require classifications and notifications that were counted for NRC performance indicator input. The inspectors observed crew performance in terms of communications; ability to take timely and proper actions; prioritizing, interpreting, and verifying alarms; correct use and implementation of procedures, including the alarm response procedures; timely control board operation and manipulation, including high-risk operator actions; and oversight and direction provided by the shift supervisor, including the ability to identify and implement appropriate TS actions. The inspectors observed the post training critique to determine that weaknesses or improvement areas revealed by the training were captured by the instructors and reviewed with the operators.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness

a. Inspection Scope

For the three equipment issues listed below, the inspectors evaluated the licensee's effectiveness of the corresponding preventive and corrective maintenance. The inspectors performed walkdowns of the accessible portions of the systems, performed in-office reviews of procedures and evaluations, and held discussions with system engineers. The inspectors compared the licensee's actions with the requirements of the Maintenance Rule (10 CFR 50.65) using VPAP 0815, "Maintenance Rule Program," and Engineering Transmittal CEP-97-0018, "North Anna Maintenance Rule Scoping and Performance Criteria Matrix." Other documents reviewed are listed in Attachment to this report.

- Motor operated valves with overcurrent higher than nameplate and thermal overload failures;
- Manual ventilation damper (connected to supply air from 1-HV-AC-4 Zone 1) is not identified on station drawings or labeled and has the potential to impact air flow to main control room and emergency switchgear room; and,
- Instantaneous overcurrent pick-up out of the required band on all three phases for Unit 2 “A” inside Recirculation Spray Pump circuit breaker.

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessments and Emergent Work Evaluation

a. Inspection Scope

The inspectors evaluated, as appropriate, for the four activities listed below: (1) the effectiveness of the risk assessments performed before maintenance activities were conducted; (2) the management of risk; (3) that, upon identification of an unforseen situation, necessary steps were taken to plan and control the resulting emergent work activities; and (4) that maintenance risk assessments and emergent work problems were adequately identified and resolved. The inspectors verified that the licensee was complying with the requirements of 10 CFR 50.65 (a)(4) and the data output from the licensee’s safety monitor associated with the risk profile of Units 1 and 2.

- Maintenance rule risk evaluation for unplanned work on 1-SI-P-1A due to through wall weld leak on suction piping concurrent with work on AMSAC, 2-IA-C-1, “C” Reserve Station Service Transformer (RSST), rack work, 1-PT-1.14, and 1-PT-75.2A;
- Maintenance rule risk evaluation for removal of scaffolding below the “C” RSST conductors in main transformer yard;
- Maintenance rule risk evaluation during operations activities involving a vital inverter; and,
- Risk assessment during a defueled condition related to maintenance activities.

b. Findings

.1 Failure to Perform Risk Assessments During a Defueled Plant Condition

Introduction: A Green non-cited violation (NCV) was identified by the NRC regarding a failure to assess the increase in risk for work associated with spent fueling pool (SFP) cooling support systems during a defueled plant condition.

Description: On October 13, 2005, the inspectors identified that the licensee was not performing outage risk assessments in accordance with their procedural guidance and the requirements of 10 CFR 50.65 (a)(4). On October 9, 2005, Unit 2 entered a defueled plant condition upon the transfer of the reactor core from the reactor vessel to the SFP. The licensee subsequently ceased performance of outage risk assessment. The licensee controls outage risk assessments via procedure VPAP-2805, “Shutdown Risk Program,” of which step 6.4, System Status Control, states that at least once per day, the Shift Technical Advisor (STA) shall review equipment and system status to (1) verify nuclear safety margins are within established outage guidelines for current Station conditions and projected Station conditions during the next 24 hours, and (2) distribute the results to Station management, the Outage Coordinator, and the Shift Supervisor. The STA performs the qualitative review by use of Station Nuclear Safety Guideline 17 to complete the Shutdown Safety Assessment (SSA) form. A section of the SSA addresses support systems which includes the spent fuel pool cooling system. This satisfies NUMARC 91-06 guidelines that state, “Maintaining decay heat removal (DHR) capability is a KEY SAFETY FUNCTION during shutdown conditions, whether the fuel remains in the reactor vessel or is off-loaded to the spent fuel pool.” However, contrary to VPAP-2805 requirements, this guideline stated that the SSA is not required when the reactor is defueled. The inspectors reviewed activities which occurred during the time that risk assessments were not performed and found that electrical system alignments, specifically an alignment to tie the ‘A’ and ‘B’ train 4160V safety-related buses together, had occurred, and switchyard work was ongoing for Unit 1. However, the licensee does not have the ability to incorporate quantitative risk assessments on the operating unit into the qualitative risk assessment for the outage unit, and the SFP cooling system incorporates two pumps, each powered from a different unit. The inspectors therefore determined that the failure to perform the risk assessments for Unit 2 work with could impact spent fueling pool cooling in a defueled condition is contrary to the requirements of 10 CFR 50.65(a)(4). 10 CFR 50.65(a)(4) requires that the licensee shall assess and manage the increase in risk that may result from the proposed maintenance activities during all conditions of plant operation, including normal shutdown operations.

<u>Analysis</u>: The inspectors referenced IMC 0612 and determined the finding is more than minor based on the failure to consider maintenance activities that could increase the likelihood of initiating events with a resultant impact on SFP cooling. The inspectors referenced IMC 0609, Appendix G, and determined that the finding is of very low safety significance, Green, since no additional qualitative assessment was warranted, and SFP cooling remained in service during the affected period. This finding impacts the cross-cutting area of human performance because of a failure of personnel to comply with the regulatory requirements.

<u>Enforcement</u>: 10 CFR 50.65 (a)(4) states in part that before performing maintenance activities the licensee shall assess and manage the increase in risk that may result from the proposed maintenance activities. Contrary to this, on October 9 - 13, 2005, the licensee failed to assess the increase in risk maintenance activities related to power supplies for SFP cooling. Because this finding is of very low safety significance and because it was entered into the licensee’s corrective action program as Plant Issue –2005-4371, this violation is being treated as a NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000339/2005005-02, Failure to Assess the Increase in Risk for Work Associated With Spent Fueling Pool (SFP) Cooling Support Systems During a Defueled Plant Condition.

.2 Failure to Perform Risk Assessment Related to Scaffold-Arc Event

Introduction: A Green non-cited violation (NCV) was identified by the NRC regarding a failure to perform risk assessments for a maintenance activity regarding the removal of scaffolding in the main transformer yard.

Description: On October 25, 2005, during the removal of scaffolding located in the main transformer yard and beneath conductors associated with 'C' Reserved Station Service Transformer (RSST), a section of scaffolding contacted a lightning arrestor connected to the 'B' phase conductor. The resultant arc involving 4160V and approximately 1600A lasted approximately 0.9 seconds. On October 26, 2005, the inspector identified that the licensee had included switchyard, which includes the main transformer yard area, in the risk assessment for day shift, but not for night shift work. Additionally, in the absence of a risk assessment acknowledging the impending work in the main transformer yard, there were, therefore, no specified risk management actions when the scaffold builders started work on the scaffolding beneath 'C' RSST conductors. The inspectors reviewed the licensee's evaluation which determined that approximately 0.5 seconds remained before protective relaying would have isolated 'C' RSST resulting in a loss of normal power to two downstream 4160V safety-related 1H and 2J buses. The licensee's subsequent risk assessment of the event resulted in an increase in risk to a core damage frequency of 9.05E-6. The inspectors determined that the failure to perform the risk assessment for the aforementioned maintenance activities is contrary to the requirements of 10 CFR 50.65(a)(4), which requires that the licensee shall assess and manage the increase in risk that may result from the proposed maintenance activities

Analysis: The inspectors concluded the finding had a credible impact on safety based on the near-miss impact of the loss of two safety-related 4160V buses, one on each unit. The inspectors referenced IMC 0612 and determined the finding is more than minor because the licensee's risk assessment failed to consider maintenance activities that could increase the likelihood of initiating events involving the challenge of critical safety functions associated with emergency power on both units and core cooling on Unit 2 (loss of 'C' RSST would have resulted in a trip of the inservice reactor coolant pump). The inspectors referenced IMC 0609, Appendix K, to evaluate the significance relative to risk. Given a baseline CDF of 8.8E-6, the event risk of 9.05E-6, and exposure time of ~6 hours, the inspectors determined that the incremental core damage probability deficit was 1.7E-10. This is below a risk threshold of 1E-6 and the finding is consequently of very low safety significance, Green. This finding impacts the cross-cutting area of human performance because of a failure of personnel to comply with the regulatory requirements in addition to a failure of personnel to comply with station procedures dictating the licensee's methods of implementing the regulation.

Enforcement: 10 CFR 50.65 (a)(4) states in part that before performing maintenance activities the licensee shall assess and manage the increase in risk that may result from the proposed maintenance activities. Contrary to this, on October 25, 2005, a risk assessment was not performed for maintenance activities related to the removal of scaffolding in the main transformer yard. Because this finding is of very low safety significance and because it was entered into the licensee's corrective action program as Plant Issue –2005-5586, this violation is being treated as a NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000338, 339/2005005-03, Failure to Perform a Risk Assessment Related to Scaffold-Arc Event.

1R14 Operator Performance During Non-Routine Evolutions and Events

a. Inspection Scope

The inspectors evaluated the response of the Unit 2 control room operators on October 7, 2005, during an unplanned trip of the Inverter Output Breaker, which occurred during the hanging of Protected Equipment Signs. The loss of 2-III Vital Bus caused the Residual Heat Removal (RHR) Heat Exchanger TCV to fail open which caused letdown flow to decrease and Reactor Coolant System (RCS) standpipe level to increase. The inspectors reviewed operator logs and plant computer data to determine if plant and operator responses were in accordance with plant design, procedures, and training. The inspectors also evaluated performance and equipment problems to ensure that they were entered the licensee's corrective action program. This event was entered into the corrective action program as Plant Issue –2005-4147.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations

a. Inspection Scope

The inspectors reviewed four operability evaluations affecting risk-significant mitigating systems, listed below, to assess, as appropriate: (1) the technical adequacy of the evaluations; (2) whether continued system operability was warranted; (3) whether other existing degraded conditions were considered as compensating measures; (4) whether the compensatory measures, if involved, were in place, would work as intended, and were appropriately controlled; (5) where continued operability was considered unjustified, the impact on TS Limiting Conditions for Operation and the risk significance in accordance with the SDP. The inspectors' review included a verification that the operability determinations were made as specified by Procedure VPAP-1408, "System Operability."

- 2J EDG operability when removing power from the relays in the 2J EDG Control Cabinet based on a loss of Unit 2 III Vital Bus per Wiring Diagram 12050-ESK-11CA, sheet 6;
- Plant Issue –2005-4365, 2-RS-MOV-255A motor current was observed to be 34% above nameplate which is greater than overcurrent previously evaluated as SAT by ET-–02-107 and in accordance with Plant Issue –2005-2776;

- Plant Issue –2005-3939, when the Residual Heat Removal (RHR) equipment was placed in service on October 2, 2005, the warmup rate of 200 degrees/hour was apparently exceeded; and,
- Plant Issue –2005-5711, during a detailed inspection of the 2J EDG engineering found loose exhaust manifold bolting and dislodged gasket material from installed gaskets.

b. Findings

No findings of significance were identified.

1R16 Operator Workarounds

a. Inspection Scope

The inspectors reviewed the cumulative effects of operator workarounds (OWAs) to assess: (1) the effect on the reliability, availability, and potential for mis-operation of a system; (2) the potential for increasing an initiating event frequency or affecting multiple mitigating systems; and (3) the cumulative effects on the ability of the operators to respond in a correct and timely manner to plant transients and accidents. The inspectors reviewed the current OWAs to determine if there were other conditions which would require actions to compensate for equipment problems or deficiencies.

b. Findings

No findings of significance were identified.

1R19 Post Maintenance Testing

a. Inspection Scope

The inspectors reviewed four post maintenance test procedures and/or test activities, as appropriate, for selected risk-significant mitigating systems to assess whether: (1) the effect of testing on the plant had been adequately addressed by control room and/or engineering personnel; (2) testing was adequate for the maintenance performed; (3) acceptance criteria were clear and adequately demonstrated operational readiness consistent with design and licensing basis documents; (4) test instrumentation had current calibrations, range, and accuracy consistent with the application; (5) tests were performed as written with applicable prerequisites satisfied; (6) jumpers installed or leads lifted were properly controlled; (7) test equipment was removed following testing; and (8) equipment was returned to the status required to perform its safety function. The inspectors verified that these activities were performed in accordance with licensee procedure VPAP-2003, "Post Maintenance Testing Program."

- Procedure 0-ECM-1502-01, "Inspection and Repair of Limitorque Motor-Operated Valves" Revision 15, per Work Order (WO) 724391;

- Procedure 0-MPM-0110-02, “Reactor Coolant Pump Coupling Disassembly and Reassembly and Reactor Coolant Pump Motor Alignment” Revision 17, per WO 52551001;
- Procedure 0-MCM-1105-06. “Assembly of the RX Vessel Head Case Exit Thermocouple Nozzle Assembly (CETNA)” Revision 4, per WO 52628805; and,
- Procedure 1-PT-14.1, “Charging Pump 1-CH-P-1A” Revision 43-P1 per WOs 572241-01 and 514945-01.

b. Findings

No findings of significance were identified.

1R20 Refueling and Outage Activities

The inspectors performed the inspection activities described below for the Unit 2 refueling outage that began on October 2, 2005, and ended October 30, 2005. The inspectors used inspection procedure 71111.20, “Refueling and Outage Activities,” to observe portions of the shutdown, cooldown, refueling, maintenance activities, and startup activities to verify that the licensee maintained defense-in-depth (DID) commensurate with the outage risk plan and applicable TS. The inspectors monitored licensee controls over the outage activities listed below. Documents reviewed during the inspection are listed in the attachment.

- Licensee configuration management, including daily outage reports, to evaluate defense-in-depth commensurate with the outage safety plan and compliance with the applicable TS when taking equipment out of service.
- Installation and configuration of reactor coolant instruments to provide accurate indication and an accounting for instrument error.
- Controls over the status and configuration of electrical systems and switchyard to ensure that TS and outage safety plan requirements were met.
- Licensee implementation of clearance activities to ensure equipment was appropriately configured to safely support the work or testing.
- Decay heat removal processes to verify proper operation and that steam generators, when relied upon, were a viable means of backup cooling.
- Controls to ensure that outage work was not impacting the ability to operate the spent fuel pool cooling system during and after-core offload.
- Reactor water inventory controls including flow paths, configurations, and alternative means for inventory addition, and controls to prevent inventory loss.
- Reactivity controls to verify compliance with TS and that activities which could affect reactivity were reviewed for proper control within the outage risk plan.
- Refueling activities for compliance with TS, to verify proper tracking of fuel assemblies from the spent fuel pool to the core, and to verify foreign material exclusion was maintained.
- Reduced inventory and mid-loop conditions for commitments to Generic Letter 88-17 to verify that these commitments were in place, that plant configuration was in accordance with those commitments, and that distractions from

unexpected conditions or emergent work did not affect operator ability to maintain the required reactor vessel level.

- Heatup and startup activities to verify that TS, license conditions, and other requirements, commitments, and administrative procedure prerequisites for mode changes were met prior to changing modes or plant conditions. RCS integrity was verified by reviewing RCS leakage calculations and containment integrity was verified by reviewing the status of containment penetrations and containment isolation valves.
- Containment closure activities, including a detailed containment walkdown prior to startup, to verify no evidence of leakage and that debris had not been left which could affect the performance of the containment sump.

b. Findings

The enforcement aspects of a risk related finding are discussed in section 1R13.

.1 Failure to Correct a Condition Adverse to Quality Regarding Small Debris in Containment

Introduction: A Green non-cited violation (NCV) for failure to correct a condition adverse to quality associated with removal of small debris in containment was identified by the NRC.

Description: On October 27 & 28, 2005 the inspectors performed a containment closeout tour in accordance with inspection procedure Attachment 71111.20, Refueling and Other Outage Activities. The specific corrective action documents initiated by the licensee associated with the inspector identified issues/discrepancies are listed in the attachment. In general, the inspectors found that the containment was free of large debris items of which the size and location could impact the performance of the containment sump. However, the inspectors identified an appreciable quantity of small debris under the seismic support plates in all three loop rooms and under all three containment air recirculation fans. All of the structures involved were installed close to the floor and, therefore, did not present an obvious appearance requiring a search for debris accumulation. Accordingly, the characterization of the debris indicated that it had accumulated over multiple operation cycles. Additionally, some of the debris under the air recirculation fans consisted of degraded material originally installed under the fan housings. The inspectors reviewed licensee procedures, 2-OP-1B, Containment Checklist, and 0-GOP-3.6, Containment Housekeeping, Closeout, and Cleanliness and did not identify any specific guidance that could have directed attention to the areas affected. Based on the amount, characterization, and location of the small debris the inspectors concluded that in the aggregate, the licensee failed to identify and correct an adverse condition to quality which is contrary to the requirements of 10 CFR 50, Appendix B, Criterion XVI which states in part, “Measures shall be established to assure that conditions adverse to quality, such as deficiencies are promptly identified and corrected.”

Analysis: The inspectors referenced IMC 0612 and determined the finding is more than minor because it could be reasonably viewed as a precursor to a significant event involving debris accumulation on the containment sump screens and a subsequent impairment to suction flow for Emergency Core Cooling System (ECCS) pumps. Although the amount of small amount of debris identified would not have impacted operability of the containment sump screens, the continued accumulation of small debris could impact operability. The inspectors further referenced IMC 0609 for the SDP review and determined the finding was of very low safety significance. Although it impacted the mitigating system cornerstone, it did not result in a loss of function per Generic Letter 91-18, did not represent an actual loss of safety function, and was not potentially risk significant due to possible external events. This finding impacts the cross-cutting area of problem identification and resolution, because it involved a deficiency in problem identification based on the licensee's failure to inspect the areas of concern during previous refueling outages.

Enforcement: 10 CFR 50, Appendix B, Criterion XVI states in part, "Measures shall be established to assure that conditions adverse to quality, such as deficiencies are promptly identified and corrected." Contrary to this on October 28, 2005, the inspectors identified an appreciable quantity of small debris under the seismic support plates in all three loop rooms and under all three containment air recirculation fans which constituted a condition adverse to quality. Because this finding is of very low safety significance and because it was entered into the licensee's corrective action program as Plant Issues –2005-4881 and –2005-4997, this violation is being treated as a NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000339/2005005-04, Failure to Correct a Condition Adverse to Quality Regarding Small Debris in Containment.

.2 Inadequate Procedure for Placing Placards on Safety-Related Equipment

Introduction: A Green, self-revealing, non-cited violation of 10 CFR 50 Appendix B Criterion V was identified as a result of the licensee's failure to establish an adequate procedure which resulted in the tripping of the 2-III Vital Bus Inverter.

Description: On October 7, 2005, while the licensee was hanging protected equipment signs before performing electrical maintenance on Unit 2, a sign or placard placed on the 2-III vital bus inverter dropped and tripped the inverter output breaker. The loss of the 2-III vital inverter had the following affects on the unit:

- 2-RH-HCV-2758, RHR heat exchanger outlet flow control, failed open resulting in an increase in RHR flow and increased letdown flow. This problem suspended activities associated with reactor vessel head lift and required operator action to stabilize RCS level.
- 2-CC-TV-203B, 'B' RHR heat exchanger component cooling (CC) outlet isolation valve failed closed. However, some core cooling for this train remained due to a 6-inch cross connect line on the CC from RHR heat exchanger discharge piping.
- Instrument air to containment was isolated requiring the start of containment air compressors.

- Chilled water flow to containment was isolated.
- Isolation valves for the containment radiation monitor, 2-RM-RMS-259/260 closed.
- Emergency Core Cooling System (ECCS) Pump Room Exhaust Air Cleanup System (PREACS) “B” Train was declared inoperable due to unavailable power.

All equipment was subsequently restored and the unit was stabilized. The licensee controls the installation of signs and barriers for protected equipment via desktop guidance, Operations Guideline 10, Revision 2, “Protected Equipment Program,” of which guideline 1 states, “Protected trains will be identified by signs and barriers installed in the plant around equipment that must remain operable.” However, this guideline does not provide directions for the installation in a manner that prevents an adverse condition such as the aforementioned loss of the 2-III vital inverter. Therefore, the inspectors determined that the licensee’s failure to establish adequate instructions or procedures to install signs or barriers for protected safety-related equipment was contrary to the requirements of 10 CFR 50, Appendix B, Criterion V, which states in part that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings.

Analysis: The failure to establish adequate instructions or procedures had a credible impact on reactor safety because the loss of the 2-III Vital Bus resulted in multiple adverse affects on safety-related equipment. The inspectors reviewed MC 0612 and determined that the finding was more than minor due to the impact on the Mitigating Systems Cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences and the related attribute of procedure quality. The inspectors reviewed MC 0609, Appendix G, Checklist 3 for the significance determination and concluded that no additional qualitative assessment was warranted. Therefore, the evaluation resulted in the characterization of Green (very low safety significance). The cause of this finding involved the cross-cutting area of human performance with respect to the development of instructions or procedures which adequately addressed methods to affix placards on safety-related components without impacting its operation.

Enforcement: 10 CFR 50 Appendix B, Criterion V states in part that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings. Contrary to the above, on October 7, 2005, guidance document, “Operations Guideline 10,” Revision 2, “Protected Equipment Program,” did not provide adequate instructions and the subsequent inadequate placement of a placard on the 2-III vital inverter resulted in the inoperability of this component. Because this finding is of very low safety significance and because it was entered into the licensee’s corrective action program as Plant Issue –2005-4147, this violation is being treated as a NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000339/2005005-05, Failure to Establish Adequate Instructions or Procedure for Placing Placards on Safety-Related Equipment.

1R22 Surveillance Testing

a. Inspection Scope

For the four surveillance tests listed below, the inspectors examined the test procedure, witnessed testing, and reviewed test records and data packages, to determine whether the scope of testing adequately demonstrated that the affected equipment was functional and operable, and that the surveillance requirements of the TS were met:

- 2-PT-61.3.4, “Total Local Leak Rate Calculation” Revision 10 and 2-PT-61.3, “Containment Type C Test” Revision 34; (isolation valve test)
- 2-PT-82J, “2J Emergency Diesel Generator Start Test;”
- 2-PT-82H, “2H Emergency Diesel Generator Start Test;” and,
- 1-PT-63.1B, “Quench Spray System- ‘B’ Subsystem”. (inservice Test)

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

1EP6 Drill Evaluation

a. Inspection Scope

On December 13, 2005, the inspectors reviewed and observed the performance of a simulator scenario that involved a steam dump failure, an AUTO STOP oil channel failure, an Electro-Hydraulic Control (EHC) leak followed by a turbine trip with Anticipated Transient Without Scram (ATWS) and a LOCA outside containment which required a site area emergency to be declared. The inspectors assessed emergency procedure usage, emergency plan classification, notifications, and the licensee’s identification and entrance of any problems into their corrective action program. This inspection evaluated the adequacy of the licensee’s conduct of the scenario and critique performance. Scenario issues were captured by the licensee in their corrective action program and were reviewed by the inspectors.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA2 Identification and Resolution of Problems

.1 Daily Review

As required by Inspection Procedure 71152, “Identification and Resolution of Problems,” and in order to help identify repetitive equipment failures or specific human performance issues for follow-up, the inspectors performed a daily screening of items entered into the licensee’s corrective action program. This review was accomplished by reviewing daily Plant Issues summary reports and periodically attending daily Plant Issue Review Team meetings.

.2 Annual Sample Review

a. Inspection Scope

The inspectors reviewed the licensee’s assessments and corrective actions for Plant Issue –2004-2728, “Boric acid found on piping between 1-SI-MOV-1860A and 1-SI-305 on first elbow at tee. Determined to be a weld leak,” relative to subsequent Plant Issue –2005-5034, “While performing 1-PT-60.5, U-1 Safeguards Valve Pit valves verification, an area of white substance was noted on the top of “A” LHSI suction line. Chemistry analysis of the sample indicate the substance is boric acid.” The review was performed to ensure that the full extent of the issue was identified, an appropriate evaluation was performed, and appropriate corrective actions were specified and prioritized.

The inspectors also evaluated the plant issue against the requirements of the licensee’s correction action program as specified in VPAP-1601, “Corrective Action Program,” VPAP-1501, “Deviations” and 10 CFR 50, Appendix B. Additional documents reviewed are listed in the Attachment.

b. Findings and Observations

A licensee identified violation associated with this review is documented in section 4OA7 of this report. Both of the plant issues noted above involved weld leaks in the same suction piping associated with the 1A LHSI pump and were identified by the licensee. Additionally, after identification of the leak on November 2, 2005, the licensee identified on November 3, 2005, that corrective actions associated with the leak identified on July 21, 2004, were potentially inadequate and would require additional review as part of the root cause evaluation for the 2005 leak.

The inspectors reviewed the licensee’s root cause evaluation for the 2004 leak which determined that defective welding during plant construction sensitized the metal adjacent to the weld and a corresponding lack of fusion may have provided the stress riser to propagate a crack. The lack of fusion had not been identified during construction examinations but was identified as part of the root cause evaluation during a review of the historical radiography test data. The licensee subsequently tested a sample of ten other welds on the LHSI suction piping by non-destructive examination (NDE) techniques and did not identify other defects. The inspectors noted that the licensee discussed sensitization of the pipe material, austenitic stainless steel, due to the higher temperatures from the welding process and subsequent exposure to conditions, e.g., chlorides in borated fluid within the pipe, which could induce stress corrosion cracking. The root cause evaluation also mentioned that another weld had been exposed to groundwater, but failed to discuss external stress corrosion cracking due to groundwater contaminants. Ultimately, the focus was more on the weld with lack of fusion as opposed to stress corrosion cracking induced from other sources.

The root cause evaluation for the 2005 leak determined that a related contributor to piping defects was external stress corrosion cracking associated with prolonged exposure to groundwater contaminants. Both the affected weld and an adjacent weld, that were found with numerous surface defects, were exposed to leaking groundwater. The inspectors concluded that an examination of an expanded sample of welds exposed to groundwater in 2004 may have identified significant defects and respective corrective actions could have precluded the leaking weld identified in 2005. The licensee's failure to implement these corrective actions is a violation of 10 CFR 50, Appendix B, Criterion XVI, which requires in part that in the case of significant conditions adverse to quality, measures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition. The enforcement aspects are discussed in section 4OA7.

.3 Semi-Annual Trend Review

a. Inspection Scope

As required by Inspection Procedure 71152, "Identification and Resolution of Problems," the inspectors performed a review of the licensee's corrective action program involving plant issue reports to identify trends that could indicate the existence of a significant safety issue. The review considered the results of daily screening of plant issues discussed in section 4OA2.1 above, licensee trending efforts, and licensee human performance. The inspector's review nominally considered the six-month period of June through December 2005, although some examples expanded beyond those dates when the scope of the trend warranted. The review also covered areas not documented in plant issue reports such as: departmental problem/challenges lists, system health reports, quality assurance audit/surveillance reports, self assessment reports, and maintenance rule assessments. The inspectors compared and contrasted their results with the results contained in the licensee's latest quarterly trend reports. Corrective actions associated with a sample of the issues identified in the licensee's trend report were reviewed for adequacy.

b. Assessment and Observations

No findings of significance were identified. The inspectors evaluated the licensee trending methodology and observed that the licensee had performed reviews. The inspectors noted that the licensee has assigned specific resources to exclusively identify negative trends and report those findings through the corrective action system. In addition, the licensee routinely reviewed cause codes, involved organizations, key words, and system links to identify potential trends in their plant issue report data. The inspectors compared the licensee trend results with the results of the inspectors' daily screening and identified a trend that the licensee had failed to identify. This discrepancy involved additional plant issues for a problem for which previous corrective actions had been implemented.

The problem involved sluggish operation of temperature control valves (TCV) for service water cooling flow to lube oil coolers for high head charging pumps. This resulted in elevated lube oil temperatures that typically exceeded the alarm setpoint of 129 degrees Fahrenheit following a start of the respective charging pump. On several occasions, operator actions were required to stabilize lube oil temperatures. While the licensee had previously identified an adverse trend in the performance of the TCV and initiated corrective actions to modify the valve actuator to improve the performance of the valves, the inspectors identified a continued adverse trend that involved ongoing problems with the modified TCV as documented in Plant Issues –2005-5077 and –2005-5622. The licensee has acknowledged that previous corrective actions were inadequate and are continuing to evaluate this condition.

4OA3 Event Followup

.1 (Closed) Licensee Event Report (LER) 05000338, 339/2004001-00: Inoperable Emergency Diesel Generators due to Shims for Exhaust Support Missing or Not Secured

On May 9, 2004, the licensee determined that both Unit 2 emergency diesel generators (EDGs) were inoperable due to missing shims on the engine exhaust stack seismic supports identified by the NRC. Operability of the EDGs was impacted by the potential of the exhaust stack to fail during a seismic event. The licensee determined the cause was from modifications of the exhaust stacks that were implemented over previous years with minimal consideration of the cumulative effects on diesel operability. Corrective actions included re-installation of the shims and re-torqued anchor bolts. Subsequently an engineering calculation determined the as found condition of the EDGs exhaust stack seismic supports did not affect operability. This LER is closed.

.2 (Closed) LER 05000339/2005001-00: Automatic Reactor Trip Due to Lightning Strike

On August 5, 2005, a Unit 2 automatic reactor trip occurred due to actuation of an Over Temperature Delta Temperature (OTDT) reactor protection signal induced by a lightning strike. The licensee performed a root cause evaluation that identified ungrounded spare T-hot and T-cold narrow range Resistance Temperature Detector (RTD) shields that share the same thermowell in the reactor coolant system and same containment electrical penetration as the active narrow range RTDs. Therefore, an electrical transient induced by lightning in the spare, unshielded RTD elements was consequently introduced into the active RTD elements and respective narrow range temperature reactor protection circuitry and resulted in the OTDT reactor trip. The RTD shields were required to be grounded to the terminal boards associated with protection channels 1 & 2 per a modification, DCP 89-41, which was implemented in 1989, and properly completed on Unit 1. The inspectors concluded that the failure to identify and correct the deficiencies associated with the July 29, 2003, event was contrary to the requirements of 10 CFR 50, Appendix B, Criterion XVI, which requires the establishment of measures to assure conditions adverse to quality are promptly identified and corrected. The enforcement aspects are documented as NCV 05000339/2005004-03, Failure to Identify and Correct Deficiencies in Instrumentation Results In Reactor Trip, in Inspection Report 50-339, 2005004. This LER is closed.

.4 (Closed) LER 05000338, 339/2005001-00: Condition Prohibited by Technical Specification - Low Temperature Overpressure Protection

On October 3, 2005, with Unit 2 in a refueling outage, the licensee determined that specified actions for Low Temperature Overpressure Protection (LTOP) requirements as defined in the respective TS Bases were not in compliance with the respective TS 3.4.12. Two independent means are required to prevent injection flow into the RCS from a low head safety injection pump; however, the licensee's procedure specified only one method, placing the pump controls in pull-to-lock. The licensee subsequently revised the procedure to include a second method for isolation of injection flow. The enforcement aspects of this performance deficiency are documented in section 4OA7 of this report. This LER is closed.

4OA5 TI 2515/160, Pressurizer Penetration Nozzles and Steam Space Piping Connections in U.S. Pressurized Water Reactors (NRC Bulletin 2004-01) (Unit 2)

The inspectors reviewed the licensee's 60-day response to NRC Bulletin 2004-01, dated July 27, 2004. The inspectors verified that the licensee's inspection activities conducted during this outage were consistent with their response.

The inspectors conducted an independent walk-down of the pressurizer to ensure that the physical conditions of the pressurizer penetrations and welds were clean and accessible for the prescribed inspections, and that there were no problems with debris, insulation, dirt, boron from other sources, physical layout, or viewing obstructions, which could have interfered with the identification of relevant indications. The inspectors were unable to see the pressurizer spray valve and the Power Operated Relief Valve (PORV) due to temporary lead shielding installed for radiation protection reasons. The inspectors reviewed both bare metal visual (BMV) and UT examination results for the following components:

- 2-RC-E-2, Weld #SW-40, 4" Pressurizer relief valve nozzle to safe end, ASME Class 1;
- 2-RC-E-2, 2-RC-SV-2551A, Weld #SW-17, 6" Pressurizer safety valve nozzle to safe end, ASME Class 1;
- 2-RC-E-2, 2-RC-SV-2551B, Weld #SW-9, 6" Pressurizer safety valve nozzle to safe end, ASME Class 1;
- 2-RC-E-2, 2-RC-SV-2551C, Weld #SW-6, 6" Pressurizer safety valve nozzle to safe end, ASME Class 1; and,

- 2-RC-E-2, Weld #SW-62, 4" Pressurizer spray valve nozzle to safe end, ASME Class 1.

Reporting Requirements are as follows:

a. For each of the examination methods used during the outage, was the examination:

1. Performed by qualified and knowledgeable personnel? (Briefly describe the personnel training/qualification process used by the licensee for this activity.)

   Yes. The licensee used knowledgeable staff members certified as Level II, VT-2 examiners in accordance with procedure TRCP-0014, "Visual Testing Program Written Practice," to conduct a direct visual examination of the bare metal surface of the above components. The examiners were also qualified as boric acid inspectors in accordance with site procedure DNAP-1004, "Boric Acid Corrosion Control Program."

   For manual UT examination of the subject dissimilar metal welds, the licensee used examiners that were certified as Level II in the UT method in accordance with their written practice for certification of ultrasonic examination personnel. The inspectors also verified that the examiners performing the examinations maintained current qualifications for the material type, diameter, and thickness in accordance with ASME Section XI, Appendix VIII, Supplement 10.

2. Performed in accordance with demonstrated procedures?

   Yes. The licensee conducted the bare metal inspection of the pressurizer penetrations in accordance with procedure VPAP-1103, "ASME Section XI Visual Examination Program (VT-1,2,3 & General)." The licensee considered this procedure to be demonstrated because examination personnel could resolve specific size of lower case alpha numeric characters at the actual visual examination distance.

   For the manual UT examination of the subject dissimilar metal welds, the licensee used site procedure number NDE-UT-810, which is equivalent to Performance Demonstration Initiative (PDI) generic procedure PDI-UT-10, Revision B. Therefore, the licensee's procedure has been demonstrated effective for the examination of dissimilar metal welds in accordance with the requirements of ASME Section XI, Appendix VIII.

3. Able to identify, disposition, and resolve deficiencies?

   Yes. The inspectors concluded that the licensee's direct visual examinations were capable of detecting leakage from cracking in pressurizer penetrations, if it had existed. The inspectors also concluded that the licensee's manual UT examination would have been able to identify stress corrosion cracking as qualified by their procedure. This conclusion was based upon the inspectors direct observations of pressurizer penetration locations, which were free of debris or deposits that could mask evidence of leakage in the areas examined. The inspectors also verified that the licensee's procedures included guidance for proper disposition and investigation of any identified deficiencies.

4. Capable of identifying the leakage in pressurizer penetration nozzle or steam space piping components, as discussed in NRC Bulletin 2004-01?

   The inspectors verified that the licensee's examination personnel were capable of identifying any leakage in pressurizer penetration nozzles or steam space piping components.

b. What was the physical condition of the penetration nozzle and steam space piping components in the pressurizer system (e.g., debris, insulation, dirt, boron from other sources, physical layout, viewing obstructions)?

   Through discussions with licensee personnel, the inspectors verified that the insulation had been removed with extreme caution so as not to disrupt any potential indications of boric acid leakage from the pressurizer at these penetration locations. The licensee personnel performed a direct visual inspection and manual UT examination of these pressurizer penetrations. The area examined was clean and free of debris or deposits or other obstructions which could mask evidence of leakage.

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

   The licensee's inspection personnel used the direct visual examination technique along with a handheld mirror.

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

   For the bare metal visual inspection, the licensee was able to view the entire circumference, 360°, around each penetration. The licensee was unable to ultrasonically examine 100% of the code required volume. Two of the three safety valves were ultrasonically inspected as part of the regular Section XI, ISI Program; the coverage limitations for these valves will be submitted as part of a relief request to the NRC. The licensee intends to submit the results of their BMV and UT examinations as part of a follow-up letter to the NRC regarding NRC Bulletin 2004-01.

e. Could small boron deposits, as described in the Bulletin 2004-01, be identified and characterized?

   The examination personnel were appropriately trained and qualified to identify small boron deposits as described in the bulletin.

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

There were no deficiencies identified that required repair.

g. What, if any, impediments to effective examinations, for each of the applied methods, were identified (e.g., centering rings, insulation, thermal sleeves, instrumentation, nozzle distortion)?

There were no impediments for an effective visual examination. Weld geometry contributed to the limited UT examination.

h. If volumetric or surface examination techniques were used for the augmented inspections examinations, what process did the licensee use to evaluate and dispose any indications that may have been detected as a result of the examinations?

Not Applicable. No augmented examinations were performed. In accordance with the licensee's response to BL 2004-01, BMV and manual UT examinations were scheduled to be completed this outage on all 5 subject pressurizer penetrations. The licensee did not identify any indications through visual or volumetric examinations that required further investigation.

I. Did the licensee perform appropriate follow-up examinations for indications of boric acid leaks from pressure-retaining components in the pressurizer system?

Not Applicable. There were no indications of boric acid leaks from pressure-retaining components in the pressurizer system.

4OA6 Meetings, including Exit

On January 11, 2006, the senior resident inspector presented the inspection results to Mr. Jack Davis and other members of the staff. The licensee acknowledged the findings. The inspectors confirmed that proprietary information was not provided during the inspection for inclusion into this report.

4OA7 Licensee-Identified Violations

The following findings of very low significance were identified by the licensee and are violations of NRC requirements which meets the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositioned NCVs.

.1 TS 5.4.1 requires that written procedures shall be established, implemented, and maintained covering the activities in the applicable procedures recommended by Regulatory Guide (RG) 1.33, Revision 2, Appendix A, February 1978, of which part 9.a. requires procedures for performing maintenance. Contrary to the above, on September 7, 2005, the licensee failed to establish adequate procedure steps in maintenance procedure 0-MCM-0121-26 5.36, "Inspection and Repair of Ingersoll-Rand Model 14ALV

General-Service Pumps (Component Cooling Pumps).” This resulted in inadequate clearances between the inboard pump bearing housing and slinger ring which subsequently led to excessive heat and a forced pump shutdown during a surveillance test on Unit 1 “A” Component Cooling Water pump. The inspectors reviewed IMCs 0612 and 0609 and determined that the finding was of very low safety significance given the availability of three other component cooling water pumps. The licensee has this finding documented in their corrective action program as Plant Issue –2005-3492.

.2 TS 3.4.12 requires that a LTOP system be operable with a maximum of one charging pump and one low head safety injection system (LHSI) pump capable of injecting into the RCS and all accumulator discharge isolation valves closed with power removed from the isolation valve operator, when accumulator pressure is greater than the Pressurizer Power Operated Relief Valves (PORV) lift setting. Contrary to the above, on October 3, 2005, the licensee identified that they were not in compliance given the methodology stated in the TS Bases for controlling injection sources for Unit 2 Reactor Coolant System (RCS). Specifically, the licensee had 2-CH-P-1A in pull-to-lock, however, additional administrative actions were required to ensure the injection sources were properly controlled in which the licensee failed to closed the associated discharge motor-operated valve (MOV) 2-CH-MOV-2286A for 2-CH-P-1A. The licensee subsequently closed the discharge MOV for the additional control of the charging pump and verified that all CLA valves were closed and de-energized. This finding had a credible impact on safety in that the LCO requires that the LTOP system is OPERABLE. Violation of this LCO could lead to the loss of low temperature overpressure mitigation and violation of the LTOP System design basis. The inspectors reviewed IMCs 0612 and 0609 and determined that the finding was of very low safety significance given the actions the licensee had taken to ensure the LTOP system was operable. The licensee has this finding documented in their corrective action program as Plant Issue –2005-3936.

.3 10 CFR 50, Appendix B, Criterion XVI requires in part that in significant cases of conditions adverse to quality, measures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition. Contrary to this on November 3, 2005, the licensee identified that corrective actions taken for a leak on the 1A low head SI pump suction piping, that was identified on July 21, 2004, did not preclude the recurrence of another leak identified on November 2, 2005. The finding had a credible impact on safety based on the development of a through-wall leak on safety-related piping. The inspectors reviewed IMCs 0612 and 0609 and determined that the finding was of very low safety significance. Although it impacted the mitigating system cornerstone, it did not result in a loss of function per Generic Letter 91-18, did not represent an actual loss of safety function, and was not potentially risk significant due to possible external events. The licensee has this finding documented in their corrective action program as Plant Issue –2005-5034.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee personnel

W. Anthes, Assistant Manager, Maintenance
G. Bischof, Director, Nuclear Safety and Licensing
J. Breeden, Supervisor, Radioactive Analysis and Material Control
W. Corbin, Director, Nuclear Engineering
J. Costello, Supervisor, Nuclear Emergency Preparedness (Virginia)
J. Crossman, Assistant Manager, Nuclear Operations
J. Davis, Site Vice President
R. Evans, Manager, Radiological Protection
R. Foster, Supply Chain Manager
S. Hammil, ISI Engineer
S. Hughes, Manager, Nuclear Operations
P. Kemp, Supervisor, Nuclear Safety & Licensing
J. Kirkpatrick, Manager, Maintenance
S. Kotowski, ISI Coordinator
L. Lane, Director, Operations and Maintenance
J. Leberstien, Licensing Technical Advisor
T. Maddy, Manager, Nuclear Protection Services
M. Main, Component Engineer
C. McClain, Manager, Organizational Effectiveness
F. Mladen, Manager, Nuclear Site Services
B. Morrison, Assistant Engineering Manager
J. Rayman, Emergency Planning Supervisor
H. Royal, Manager, Nuclear Training
G. Salomone, Licensing
M. Sartain, Manager, Nuclear Engineering
J. Scott, Supervisor, Nuclear Training (operations)
K. Taylor, Component Engineer (BAACP)
J. Underwood, Steam Generator Coordinator
R. Williams, Component Engineer

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened and Closed

05000339/2005005-01	NCV	Failure to Identify Locations of Boric Acid Leakage (Section 1R08.2)
05000339/2005005-02	NCV	Failure to Assess the Increase in Risk for Work Associated With Spent Fueling Pool (SFP) Cooling Support Systems During a Defueled Plant Condition (Section 1R13.1)
05000338, 339/2005005-03	NCV	Failure to Perform a Risk Assessment Related to Scaffold-Arc Event (Section 1R13.2)
05000339/2005005-04	NCV	Failure to Correct a Condition Adverse to Quality Regarding Small Debris in Containment (Section 1R20.1)
05000339/2005005-05	NCV	Failure to Establish Adequate Instructions or Procedure for Placing Placards on Safety-Related Equipment (Section 1R20.2)

Closed

05000338, 339/2004001-00	LER	Inoperable Emergency Diesel Generators Due to Shims for Exhaust Support Missing or Not Secured (Section 4OA3.1)
05000339/2005001-00	LER	Automatic Reactor Trip Due to Lightning Strike (Section 4OA3.2)
05000338, 339/2005001-00	LER	Condition Prohibited by Technical Specification - Low Temperature Overpressure Protection (Section 4OA3.4)
2515/160 (Unit 2)	TI	Pressurizer Penetration Nozzles and Steam Space Piping Connections in U.S. Pressurized Water Reactors (NRC Bulletin 2004-01) (Section 4OA5)

LIST OF DOCUMENTS REVIEWED

Section 1R01: Adverse Weather

Documents

- Plant Issue –2005-5266, Licensee identified problem with controlling adequate temperature for the Unit 1 Rod Drive area.
- Plant Issue –2005-5444, NRC identified problem with low temperature alarm switch setpoints in the Unit 1 auxiliary feedwater pump house.
- Plant Issue –2005-5505, NRC identified concern with low temperature on the Woodward governors associated with the unit 1 & 2 turbine driven auxiliary feedwater pumps.
- Plant Issue –2005-5513, NRC identified concern with low temperature limits in the service water pump house.

Section 1R08: Inservice Inspection (ISI) Activities

Examinations Observed

Ultrasonic Testing (UT):

- 3"-SI-423-1502-Q2, Pipe to Elbow weld on inlet line to 2-SI-TK-2, ASME Class 2
- 3"-SI-457-1502-Q1, Pipe to Elbow weld downstream of 2-SI-MOV2869B, ASME Class 2
- 32"-SHP-402-601-Q2, Pipe to valve weld on B 32" main steam line in MSVH, ASME Class 2

Liquid Penetrant (PT)

- 3"-SI-423-1502-Q2, Pipe to Elbow weld on inlet line to 2-SI-TK-2, ASME Class 2

Examination Records

Ultrasonic Testing (UT):

- 2-RC-E-2, Weld #SW-40, 4" Pressurizer relief valve nozzle to safe end, ASME Class 1
- 2-RC-E-2, 2-RC-SV-2551A, Weld #SW-17, 6" Pressurizer safety valve nozzle to safe end, ASME Class 1
- 2-RC-E-2, 2-RC-SV-2551B, Weld #SW-9, 6" Pressurizer safety valve nozzle to safe end, ASME Class 1
- 2-RC-E-2, 2-RC-SV-2551C, Weld #SW-6, 6" Pressurizer safety valve nozzle to safe end, ASME Class 1
- 2-RC-E-2, Weld #SW-62, 4" Pressurizer spray valve nozzle to safe end, ASME Class 1
- 14"-RC-410-2501R-Q1, Weld #SW-5, Pressurizer Surge Line, ASME Class 1
- 6"-SI-570-1502-Q2, Weld #SW-73, Boron Injection Tank Inlet, ASME Class 2
- 6"-SI-569-1502-Q2, Weld #SW-55, Boron Injection Tank Outlet, ASME Class 2

Visual Testing (VT):

- 2-RC-E-2, Weld #SW-40, 4" Pressurizer relief valve nozzle to safe end, ASME Class 1
- 2-RC-E-2, 2-RC-SV-2551A, Weld #SW-17, 6" Pressurizer safety valve nozzle to safe end, ASME Class 1
- 2-RC-E-2, 2-RC-SV-2551B, Weld #SW-9, 6" Pressurizer safety valve nozzle to safe end, ASME Class 1

- 2-RC-E-2, 2-RC-SV-2551C, Weld #SW-6, 6" Pressurizer safety valve nozzle to safe end, ASME Class 1
- 2-RC-E-2, Weld #SW-62, 4" Pressurizer spray valve nozzle to safe end, ASME Class 1
- 14"-RC-410-2501R-Q1, Weld #SW-5, Pressurizer Surge Line, ASME Class 1

Radiographic Examination (RT)

- 2"-RC-453-1502-Q1, Loop 'A' Drain line, ASME Code Class 1

<u>Recordable Indications</u>

- 2-WS-PH-7028, VT-3
- 2-CH-SH-33, VT-3
- 6"-SHP-438-601-Q2, UT

<u>Nondestructive Examination</u>

- Dominion Augmented Inspection Manual, Revision 40
- NAPS Unit 2, Inservice Inspection Plan for the Third Inspection Interval, Components and Component Supports, Revision 4 August 2004
- NASES-6.14, Controlling Procedure for ASME Section XI Repair and Replacement Programs, Revision 12
- VPAP-1103, ASME Section XI Visual Examination Program (VT-1,2,3 and General), Revision 10
- NDE-UT-812, Ultrasonic Examination of Austenitic Piping Wels in Accordance with ASME Section XI, Appendix VIII, Revision 0
- NDE-UT-811, Ultrasonic Examination of Ferritic Piping Wels in Accordance with ASME Section XI, Appendix VIII, Revision 0
- NDE-UT-810, Ultrasonic Examination of Dissimilar Metal Welds in Accordance with ASME Section XI, Appendix VIII, Revision 1
- NDE-PT-701, Liquid Penetrant Examination, Revision 5
- NASES-6.23, Boric Acid Corrosion Control Program (BACCP), Revision 2
- DNAP-1004, Boric Acid Corrosion Control Program (BACCP), Revision 3
- Inservice Inspection Manual, ASME Section XI Visual Training/Certification Program and Visual Program, Revision 1
- Procedure 2-PT-48.5, Leakage Inspection Above Reactor Vessel Head, Revision 1
- Procedure 2-PT-48.4, Bare Metal Inspection of Vessel BMI Nozzles, Revision 1
- Procedure 2-PT-48.3, Visual Inspection Borated Systems in Containment, Revision 1
- Procedure 2-PT-48.2, Visual Inspection of ASME XI Class 2 and Class 3 Boundary Components Outside Reactor Containment, Revision 4
- Procedure 2-PT-48.1, Visual Inspection of ASME XI Class 2 Pressure Boundary Components Inside Reactor Containment, Revision 6
- Procedure 2-PT-48.1A, Visual Inspection of Class 2 and 3 Bolted Components Inside Reactor Containment - Group A, Revision 0
- Procedure 2-PT-48.2A, Visual Inspection of Class 2 and 3 Bolted Components Outside Reactor Containment - A Group, Revision 0
- Procedure 2-PT-48, Visual Inspection of Pressure Boundary Components, Revision 16

- Procedure 2-PT-46.21, RCS Pressure Boundary Components Affected by Boric Acid Accumulation, Revision 22
- VEPCO letter to NRC, June 3, 1988, Response to Generic Letter 88-05
- Boric Acid Corrosion Control Program system health report, 2005-Q2

Steam Generator

- VEPCO letters to NRC, April 1, 2002 and May 16, 2002, Response to Bulletin 2002-001, Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity
- 03-5071002, Secondary Side Visual Inspection Plan and Procedure for Dominion, North Anna Unit 2 N2R17, Revision 0
- NAP-SGPMS-001, North Anna Site Specific Eddy Current Analysis Guidelines, Revision 8
- NAPS-SGMIP-001, North Anna Power Station Units 1 and 2 Steam Generator Monitoring and Inspection Plan
- S/G Monitoring Program Pre-Outage Assessment for North Anna Unit 2 - Fall 2005
- 54-ISI-400-14, Multi-Frequency Eddy Current Examination of Tubing, 8/12/05
- 2 2164p-7, Steam Generator Machine Vision System Operating Instructions, 9/8/05
- 54-ISI-401-00, Computerized Data Screening (CDS) Sort Logic Development, ½1/97
- 51-5071231-00, North Anna Unit 2 EOC17 - EPRI Appendix H Eddy Current Technique Qualification
- 51-9001862-000, North Anna Automated Data Analyst Qualification
- Work Order (WO) 00526425 02, Perform Sludge Lance and FOSAR for SG B

Other Documents

- ITC-SA-05-012, Inservice Inspection (ISI) Program self-assessment
- Program Health Report, 2005 QTR 2, Inservice Inspection Program (ISI)
- Program Health Report, 2005 QTR 2, Boric Acid Corrosion Control Program
- Assessment CEN-02-01, Generic Letter 88-05 Commitment Effectiveness

Plant Issues

- –2005-3924, Boric acid accumulation observed below a thermocouple connection on the U2 reactor vessel head
- –2005-3882, Boron leakage identified from numerous components
- –2005-3896, Additional boron leakage identified from numerous components
- –2005-4110, Boric acid indication on 2-CH-ICV-3001
- –2005-4094, Boron leaks not previously identified
- –2005-3991, Components identified with boric acid leaks
- –2005-3941, Leaking items reported during outage PTs and walk downs
- –2005-4388, As-left conditions following cleaning the U-2 reactor vessel head bare metal
- –2005-4281, Inspection of Unit 2 containment liner that had previous wall thinning indications as required by the ASME IWE program

- –2005-2014, OE 14406 Lessons learned from assessments of the Boric Acid Corrosion Control Program

Section 1R12: Maintenance Effectiveness

Plant Issues

- –2005-1514, the grommet on 2-EP-BKR-2C1-4-B3R that protects feeder leads to bucket was found to be degraded
- –2005-3204, defective breaker and control transformer were identified while performing WO 605163-01
- –2005-3225, attempted to start 2-QS-P-1B and breaker OL actuated
- –2005-3680, manual ventilation damper not identified on station drawings
- –2005-3685, motor current was observed to be 24.8% over nameplate
- –2005-4098, thermal overload did not trip breaker during 300% test
- –2005-4150, motor current was observed to be 16.4% above nameplate
- –2005-4354, while performing 0-MPM-0302-02, found instantaneous pick-up out of required band on all phases
- –2005-4365, motor current was observed to be 34% above nameplate
- –2005-4424, during performance of 480 VAC breaker refurbishments, a procedural problem was identified with AS-LEFT trip verification
- –2005-4754, there are conflicting settings for overload between procedures and vendor information
- –2005-4809, several overloads did not trip during performance of 2-PT84.5B

Documents

- Procedure 0-FPM-0307-01, “Testing of Klockner-Moeller Thermal Overload,” Revision 13
- Procedure 0-ECM-0307-01, “Replacement of Thermal Overload Devices,” Revision 11
- Vendor Technical Manual 59-K408-F0003

Section 1R20: Refueling and Outage Activities

Plant Issues from Inspector Containment Walkdown

- –2005-4866, Snubber, 2-WT-HSS-407.01A, found with rod eye end of the snubber bound in the pipe clamp.
- –2005-4879, A baseplate for the “C” Steam Generator Secondary Access Platform has a small area of grout missing at one corner partially exposing the shank of the anchor bolt.
- –2005-4997, Loose material was identified under the containment air recirc fans which may have migrated to the containment sump during a DBA.
- –2005-4998, Insulation and associated covering for 2-BD-105 was identified degraded and may have migrated to the sump during a DBA.
- –2005-4981, Various small objects and material were identified and removed from supports below the electrical penetration area floor grating on the 241' elevation of containment.

- –2005-4906, A concern was identified with permanently installed scaffold member (tube-lock) frames in the containment basement that support temporary lead shielding associated with the reactor head storage stand. Local areas of the scaffold frames appeared to have the potential for interaction with adjacent piping and conduits during a seismic event.
- –2005-4881, During containment close-out walkdown the following deficiencies were noted:
  - All three loop rooms needed debris removed from under the seismic support steel plates
  - A piece of tape was removed from the screen to the “C” 92 fan
  - A small piece of flat metal approx 2" long was removed from I-beam in annulus of 262" elevation
  - 6 insulation deficiencies were noted
  - 2-RC-HCV-2556A has boric acid on bonnet (item also in Plant Issue –2005-4880)
  - 2-RC-30 packing leak with boric acid (item also in Plant Issue –2005-4880)
  - Handrail to “B” S/G Channel head platform was removed and stored under catwalk
  - Piece of tube-lock was left attached in “A” motor cube next to loop bypass valve

  All items have been logged in the outage housekeeping log for disposition

Other Plant Issues

- –2005-4501, Following a review of pre-operational test data relative to debris found in the Unit 2 recirculation spray heat exchangers, no construction documentation of flushing the RS piping was located.
- –2005-4482, While performing a liquid penetrant examination on weld 19 located at PEN-75 in containment, numerous rejectable linear indications were discovered.
- –2005-4009, Boroscope inspection of recirculation spray heat exchangers 2-RS-E-1A, B and D revealed small pieces of debris that can likely be removed through the respective 1.5" drain lines. Inspection of 2-RS-E-1C revealed an appreciable amount of debris scattered around the circumference of the tubesheet.

Documents

- Procedure 2-GOP-13.0, "Alternate Core Cooling Method Assessment"
- Dominion Memorandum dated 9/22/05, 2005 Outage Plan Safety Review North Anna Unit 2