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

January 23, 2004

Southern Nuclear Operating Company, Inc.
ATTN: J. Gasser, Jr., Vice President
Vogtle Electric Generating Plant
P. O. Box 1295
Birmingham, AL 35201-1295

SUBJECT: VOGTLE ELECTRIC GENERATING PLANT - NRC INTEGRATED INSPECTION REPORT 05000424/2003005 AND 05000425/2003005 (NOED NO. 03-6-004)

Dear Mr. Gasser:

On December 27, 2003, the US Nuclear Regulatory Commission (NRC) completed an inspection at your Vogtle Electric Generating Plant (VEGP), Units 1 and 2. The enclosed integrated inspection report documents the inspection results, which were discussed on January 9, 2004, with Mr. W. Kitchens and other members of your staff.

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

This report documents one NRC-identified finding of very low safety significance (Green) that was determined to involve a violation of NRC requirements. However, because of its very low safety significance and because it was entered into your corrective action program, the NRC is treating this finding as a non-cited violation (NCV) consistent with Section VI.A.1 of the NRC Enforcement Policy. If you contest the NCV in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the United States Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington DC 20555-0001; with copies to the Regional Administrator, Region II; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at Vogtle.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter, its enclosures, 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 the NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm.html (the Electronic Reading Room).

Sincerely,

/RA/

Brian R. Bonser, Chief
Reactor Projects Branch 2
Division of Reactor Projects

Docket Nos.: 50-424, 50-425
License Nos.: NPF-68, NPF-81

Enclosure: Inspection Report 05000424/2003005
and 05000425/2003005
w/Attachment: Supplemental Information

cc w/encl: (See page 3)

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***FOR PREVIOUS CONCURRENCE - SEE ATTACHED COPY**

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DATE	1/23/2004	1/23/2004	1/23/2004	1/23/2004			
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U. S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket Nos.:	50-424, 50-425
License Nos.:	NPF-68, NPF-81
Report Nos.:	05000424/2003005 and 05000425/2003005
Licensee:	Southern Nuclear Operating Company, Inc.
Facility:	Vogtle Electric Generating Plant
Location:	7821 River Road Waynesboro, GA 30830
Dates:	September 28, 2003 - December 27, 2003
Inspectors:	J. Zeiler, Senior Resident Inspector T. Morrissey, Resident Inspector J. Blake, Senior Project Manager (Section 1R08) C. Rapp, Senior Project Engineer (Section 1R06)
Approved by:	Brian R. Bonser, Chief Reactor Projects Branch 2 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000424/2003-005, 05000425/2003-005; 09/28/2003 - 12/27/2003; Vogtle Electric Generating Plant, Units 1 and 2; Event Followup.

The report covered a three-month period of inspection by resident inspectors and announced inspections by a regional reactor inspector and a senior project engineer. One Green non-cited violation (NCV) was identified. The significance of most findings is indicated by their color (Green, White, Yellow, or 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 management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

A. NRC-Identified and Self-Revealing Findings

Cornerstone: Mitigating Systems

- Green. An NRC-identified NCV of Technical Specification (TS) 5.4.1.a was identified for failure to perform an adequate Unit 1 containment closeout inspection in accordance with plant procedures.

  This finding is greater than minor because it affected the equipment performance attribute of the Mitigating System Cornerstone, in that, the failure to perform an adequate closeout inspection resulted in debris left in containment that could have resulted in inadequate net positive suction head for the Residual Heat Removal (RHR) system in the recirculation phase during a design basis loss of coolant accident (LOCA). This would have affected the cornerstone objective of ensuring the availability, reliability and capability of systems (i.e. RHR in recirculation) that respond to initiating events (such as a design basis LOCA). The direct cause of this finding involved the cross-cutting area of Human Performance. (Section 4OA3)

B. Licensee-Identified Violations

None.

REPORT DETAILS

Summary of Plant Status

Unit 1 began the period in a refueling outage. The refueling outage was completed on October 21 and the unit reached 100 percent Rated Thermal Power (RTP) on October 26. On November 21, power was reduced to 50 percent RTP to repair a steam leak on the1B main feedwater pump discharge vent pipe. The unit was returned to 100 percent RTP on November 24 and remained at essentially 100 percent RTP for the remainder of the inspection period.

Unit 2 operated at essentially 100 percent RTP throughout the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity

1R01 Adverse Weather Protection

a. Inspection Scope

The inspectors performed a walkdown of both unit's Refueling Water Storage Tank (RWST) and Nuclear Service Cooling Water (NSCW) systems to verify these systems would remain functional during low temperature weather conditions. The inspectors reviewed the preventative maintenance activities associated with heat tracing and freeze protection systems to verify they were appropriately scheduled and completed prior to the onset of cold weather. The inspectors reviewed compensatory actions for degraded or inoperable heat trace and freeze protection equipment to verify implementation. Additionally, the inspectors reviewed the condition report (CR) database to verify that adverse weather related items were being identified and appropriately resolved. Documents reviewed are listed in the Attachment.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment

a. Inspection Scope

Partial Walkdowns. The inspectors performed partial walkdowns of the following two systems to verify correct system alignment while redundant or backup equipment was inoperable. The inspectors checked for correct valve and electrical power alignments by comparing positions of valves, switches, and breakers to the positions specified in the procedures listed in the Attachment. Additionally, the inspectors reviewed the CR database to verify that equipment alignment problems were being identified and appropriately resolved.

- Unit 2 Class 1E 125V DC switchgear 2BD1, 2CD1, and 2DD1 during troubleshooting activities on battery chargers associated with switchgear 2AD1
- 1A Motor Driven Auxiliary Feedwater (MDAFW) pump and Turbine Driven Auxiliary Feedwater (TDAFW) pump systems while the 1B MDAFW pump was out of service

Complete Walkdowns. The inspectors conducted a detailed review of accessible portions of the Unit 1 Safety Injection (SI) system. The inspectors used procedure 11105-1, Safety Injection System Alignment; procedure 13105-1, Safety Injection System; and Drawings 1X4DB119, 1X4DB120, and 1XDB121 to verify adequate system alignment, electrical power availability, labeling, hangers and support installation, and support systems status. The inspectors also reviewed system health reports, maintenance rule monthly reports, CR database, and outstanding maintenance work orders (MWOs) to verify that alignment and equipment discrepancies were being identified and appropriately resolved.

b Findings

No findings of significance were identified.

1R05 Fire Protection

a. Inspection Scope

The inspectors walked down the following 12 plant areas to verify the licensee was controlling combustible materials and ignition sources as required by procedures 92015-C, Use, Control, and Storage of Flammable/Combustible Materials, and 92020-C, Control of Ignition Sources. The inspectors assessed the material condition of fire detection, suppression, and protection systems and reviewed the licensee's fire protection Limiting Condition for Operation log and CR database to verify that the corrective actions for degraded fire protection equipment were identified and appropriately prioritized. The inspectors also reviewed the licensee's fire protection program to verify the requirements of Updated Final Safety Analysis Report (UFSAR) Section 9.5.1, Fire Protection Program, and Appendix 9A, Fire Hazards Analysis, were met. Documents reviewed are listed in the Attachment.

- Unit 1, Fuel Handling Building Level B
- Unit 2, Train B cable spreading room
- Unit 2, Auxiliary Feedwater Building
- Unit 1, Auxiliary Building Level 1
- Unit 2, Main Steam Isolation Valve Room North
- 1A SI pump room
- 1B SI pump room
- 2B Emergency Diesel Generator (EDG) Building
- Unit 1, TDAFW and 1A MDAFW pump rooms
- 2B High Head Safety Injection (HHSI) pump room
- Unit 2, Auxiliary Building Level 2
- Unit 1, Main Steam Isolation Valve Room South

b. Findings

No findings of significance were identified.

1R06 Flood Protection

a. Inspection Scope

The inspectors reviewed the licensee's internal and external flooding mitigation procedures and equipment to verify they were consistent with the licensee's design requirements and risk analysis assumptions. For internal flooding, the inspectors reviewed the UFSAR and Individual Plant Examination and walked down the areas listed below which contained risk-significant structures, systems and components (SSCs) below flood level to verify flood barriers were in place. Water-tight doors were observed to verify they were closed as required by licensee procedures, the locking mechanism functioned properly, and the sealing gasket material was intact and undamaged. The inspectors reviewed selected alarm response procedures to verify alarm setpoints and setpoints for sump pump operation were consistent with the UFSAR, the setpoint index, and Technical Specifications (TS). Areas walked down included the following:

- Unit 1 'A' Train Corridor on Control Building Level 'B'
- Unit 1 and Unit 2 Containment Spray Pump rooms
- Unit 1 and Unit 2 Component Cooling Water Pump rooms

The inspectors discussed external flooding preparation with engineering personnel to verify preparation and compensatory measures met the licensee's design requirements and risk analysis assumptions. The inspectors checked selected cable tunnels to verify the sump pumps functioned and adverse water conditions did not exist. The inspectors reviewed a sampling of CRs to verify the licensee was identifying and correcting problems associated with flood detection and protection of SSCs. Documents reviewed are listed in the Attachment.

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection (ISI)

a. Inspection Scope

The inspectors reviewed the inspection documentation for ISI work activities during the last outage of the 2nd period of the 2nd ISI interval, and also reviewed selected supporting records. The documentation and supporting records were reviewed for compliance to the TS, the ASME Boiler and Pressure Vessel Code, Section XI, 1989 Edition, with no Addenda, and the recently approved (September 30, 2003) Relief Request for Risk-Informed Inservice Inspection Program for Class 1 and 2 Piping. The inspectors reviewed the results of the following inspections:

- Weld # 11201-030-14, (4" Elbow to Pipe) - UT examination
- Weld # 11204-V6-001-W01, (BIT inlet nozzle to vessel head) - UT & PT examinations
- Weld # 11204-V6-001-W04, (BIT inlet nozzle to vessel head) - UT & PT examinations
- Weld # 11205-007-17, (8" Tee to Pipe)
- Weld # 11205-008-17, (8" Tee to Pipe)

Qualification and certification records for examiners, equipment and consumables, and nondestructive examination (NDE) procedures for the above ISI examination activities were reviewed. The following procedures were reviewed:

- ES-MISN-V-481, PDI Generic Procedure for the Ultrasonic Examination of Austenitic Pipe Welds, Version 1.0, September 19, 2003
- ES-MISN-V-605, Southern Nuclear Operating Company Materials & Inspection Services Color Contrast, Solvent-Removable Liquid Penetrant Examination Procedure, Version 1.0, September 17, 2003
- ES-MISN-V-411. Southern Nuclear Operating Company Materials & Inspection Services Manual Ultrasonic Examination of Pressure Vessel Welds (Greater Than 2-inches in Thickness) Version 1.0, September 17, 2003.

Welds # 11205-007-17 and # 11205-008-17 were on the downstream side of the RHR system mixing tee, where reactor coolant flow by-passing the RHR heat exchangers recombines with the portion of the flow that went through the coolers. The piping downstream of the welds was inspected for a minimum of 6-inches because operating experience from a foreign plant had resulted in thermal fatigue cracking of the base material downstream of the mixing tee. The inspectors reviewed the following documents regarding indications discovered in the downstream piping:

- Weld # 11205-007-17: Indication evaluation record # S03V1U510 and Indication Notification record # 103V1002.
- Weld # 11205-008-17: Indication evaluation record # S03V1U500 and Indication Notification record # 103V1001.

The indication evaluation records provided justification for acceptance of the indications detected in the base-material of the piping material downstream of the weld. The indication notification records provided engineering recommendation to re-inspect the indications at the next refueling outage.

The inspectors also reviewed the ongoing current examination of the steam generators. Data acquisition and evaluation operations were observed.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification

a. Inspection Scope

The inspectors observed operator performance during licensed operator simulator training associated with Requalification Segment 20036. The inspectors evaluated operator performance during the conduct of a simulator scenario that began with a reactor startup interrupted by an inoperable bypass feed isolation valve requiring a reactor shutdown. A misaligned control rod during the shutdown led to a manual reactor trip complicated by a stuck open steam dump valve, two rods not fully inserting, and loss of auxiliary component cooling water. The inspectors specifically assessed the following areas:

- Correct use of unit operating and system operating procedures including 12003-C, Reactor Startup (Mode 3 to Mode 2); 12004, Power Operation (Mode 1); 12005-C, Reactor Shutdown to Hot Standby (Mode 2 to Mode 3); and 13009-1, CVCS Reactor Makeup Control System
- Correct use of abnormal and emergency operating procedures including 18022-C, Loss of Auxiliary Component Cooling Water; 18003-C, Rod Control System Malfunction; 19000-C, E-0 Reactor Trip or Safety Injection; and 19001-C, ES-0.1 Reactor Trip Response
- Ability to identify and implement appropriate TS actions
- Clarity and formality of communications in accordance with procedure 10000-C, Conduct of Operations
- Proper control board manipulations including critical operator actions
- Quality of supervisory command and control
- Effectiveness of post-evaluation critique

b Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessments and Emergent Work Evaluation

a. Inspection Scope

The inspectors reviewed the following six risk significant and emergent MWOs to verify plant risk was properly assessed by the licensee prior to conducting the activities. The inspectors reviewed risk assessments and risk management controls implemented for these activities to verify they were completed in accordance with procedure 00354-C, Maintenance Scheduling, and 10 CFR 50.65(a)(4). The inspectors also reviewed the CR database to verify that maintenance risk assessment problems were being identified at the appropriate level, entered into the corrective action program, and appropriately resolved.

- 1B Main feed pump vent piping leak repair (MWO 10303089)
- 1B EDG air compressor 1 repair (MWO 10303168)
- Unit 2, Class 1E 125V DC switchgear 2AD1 battery chargers troubleshooting activities (MWO 20303311)
- 1B MDAFW pump outage (MWO 10302866)
- Air pump replacement on Main Steam Isolation Valve 1HV3006A (MWO 10303240)
- 1B MDAFW pump discharge valve outage (MWOs 10303008 and 10303009)

b. Findings

No findings of significance were identified.

1R14 Operator Performance During Non-Routine Plant Evolutions

a. Inspection Scope

For the three non-routine plant evolutions described below, the inspectors reviewed the operating crew's performance, reviewed operator logs, control board indications, and plant computer data to verify that operator response was in accordance with the associated plant procedures.

- October 21, Unit 1 reactor startup in accordance with procedure 12003-1, Reactor Startup (Mode 3 to Mode 2), and procedure LPPT-GAE/GBE-01, Low Power Physics Test Program with Dynamic Rod Worth Measurement
- October 22, Unit 1 manual steamline isolation actuation upon report of a failed high pressure hose in the steam valve gallery
- October 26-27, Unit 1 minor plant transients associated with inadvertent instrument air isolation to 6B feedwater heater high level dump and level control valves and an unrelated failed open steam generator 3 atmospheric relief valve, 1PV3020 (CRs 2003003189 and 2003003190)

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing

a. Inspection Scope

The inspectors either observed post-maintenance testing or reviewed the test results for the following seven maintenance activities to verify that the testing met the requirements of procedure 29401-C, Work Order Functional Tests, for ensuring equipment operability and functional capability were restored. The inspectors also reviewed the test procedures to verify the acceptance criteria was sufficient to meet the TS operability requirements.

- 1A EDG Woodward 701 Digital Speed Controller replacement (MWO 10301383)
- Troubleshoot/repair 1A MDAFW pump discharge control valve 1HV5137 failure (MWO 10302860)
- Troubleshoot/repair inadvertent opening of Unit 1 steam generator atmospheric relief valve 1PV3020 (MWO 10302914)
- 1B MDAFW pump outage (MWO 10302866)
- Unit 2 Class 1E 125V DC switchgear 2AD1 battery chargers troubleshooting activities (MWO 20303311)
- Diesel fire pump system outage (MWOs C0300070, C0200110, and C0300091)
- 1B MDAFW pump discharge valve outage (MWOs 10303008 and 10303009)

b. Findings

No findings of significance were identified.

1R20 Refueling and Outage Activities

Unit 1 Refueling Outage

a. Inspection Scope

The inspectors reviewed the licensee’s Pre-Outage Schedule Risk Assessment Report, dated September 22, 2003, and the Refueling Outage Schedule, Revision A, to confirm that the licensee had appropriately considered risk, industry experience, and previous site-specific problems in developing and implementing the outage plan. During the refueling outage, the inspectors observed portions of the shutdown and cooldown processes and monitored licensee controls over the outage activities listed below. Documents reviewed are listed in the Attachment.

- Outage related risk assessment monitoring
- Controls associated with shutdown cooling, reactivity management, reduced inventory activities, electrical power alignments, containment integrity and closure, and spent fuel pool cooling
- Implementation of equipment clearance activities
- Core refueling operations
- Reactor mode changes
- Reactor heatup and repressurization
- Reactor initial startup activities
- Power ascension and full power testing

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing

a. Inspection Scope

The inspectors reviewed the following five surveillance test procedures and either observed the testing or reviewed test results to verify that testing was conducted in accordance with the procedures and that the acceptance criteria adequately demonstrated that the equipment was operable. This review included one inservice test (IST) (i.e., procedure 14802-1) and one containment isolation valve test (i.e., procedure 14340-1). Additionally, the inspectors reviewed the CR database to verify that the licensee had adequately identified and implemented appropriate corrective actions for surveillance test problems.

- 14666-1, Train A Diesel Generator and ESFAS Test
- 14721-1, ECCS Subsystem Flow Balance and Check Valve Refueling Inservice Test
- 14980B-1, Diesel Generator Operability Test (1B, slow start)
- 14340-1, Containment Penetration No. 40 Fire Protection Water Supply Local Leak Rate Test
- 14802-1, NSCW Pumps and Check Valve IST and Response Time Test (Train A)

b. Findings

No findings of significance were identified.

1REP Equipment Availability, Reliability, and Functional Capability (Pilot Procedure)

a. Inspection Scope

Operability Evaluations. The inspectors reviewed the following nine evaluations to verify that they met the requirements of procedure 00150-C, Condition Reporting and Tracking System. This scope included a review of the technical adequacy of the evaluations, the adequacy of compensatory measures, and the impact on continued plant operation.

- Restart time of Containment Coolers exceeded acceptance criteria during ESFAS testing (CR 2003003043)
- 1A MDAFW pump discharge control valve 1HV5137 shows full open with less than expected flow (CR 2003003157)
- Malfunction of Unit 2 Solid State Protection System (SSPS) test switch during surveillance testing (CR 2003003186)
- Stroke time failure of Unit 2 accumulator vent valve 2HV0943B (CR 2003003338)
- Output amperage oscillations of 1E 125V battery chargers 2AD1CA and 2AD1CB (CR 2003003388)
- Temporary Modification (TM) 2003-V1T066, Disable Low Air Pressure alarm for 1B EDG Air Receiver No. 1
- TM 2003-V1T061, Isolate Position Indication of Valve 1HV8806 from System Status Monitoring Panel
- TM 2003-V1T067, Adjust Thrust Bearing Wear Alarms of Main Feedwater Pumps

- Containment penetrations for Control Rod Drive System lift circuits not properly analyzed for penetration protection (CR 2003003605)

Maintenance Effectiveness. The inspectors reviewed the following three equipment problems and associated licensee CRs to evaluate the effectiveness of the licensee's handling of equipment performance problems and to verify the licensee's maintenance efforts met the requirements of 10 CFR 50.65 (the Maintenance Rule) and procedure 50028-C, Engineering Maintenance Rule Implementation. The reviews included adequacy of the licensee's failure characterization, establishment of performance criteria or 50.65 (a) (1) performance goals, and adequacy of corrective actions. Other documents reviewed during this inspection included control room logs, system health reports, the maintenance rule database, and MWOs. Also, the inspectors interviewed system engineers and the maintenance rule coordinator to assess the accuracy of identified performance deficiencies and extent of condition.

- Failure of 1A piping penetration ventilation system and breaker 1AB1501 to shed during ESFAS Train A testing (CR 2003003020)
- Failure of 1A MDAFW pump discharge control valve 1HV5137 (CR 2003003157)
- Failure of Unit 1 TDAFW 6CR relay (CR 2003003177)

Temporary Plant Modifications. The inspectors evaluated the following four Temporary Modifications and associated 10 CFR 50.59 screenings against the system design basis documentation and UFSAR to verify that the modifications did not adversely affect the safety functions of important safety systems. Additionally, the inspectors assessed if the modifications were developed and implemented in accordance with licensee procedure 00307-C, Temporary Modifications.

- TM 2003-V1T061, Isolate Position Indication of Valve 1HV8806 from System Status Monitoring Panel
- TM 2003-V1T063, Sealant Leak Repair Feedwater Valve 1-1305-X4-966
- TM 2003-V1T066, Disable Low Air Pressure alarm for 1B EDG Air Receiver No. 1
- TM 2003-V1T067, Adjust Thrust Bearing Wear Alarms of Main Feedwater Pumps

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

1EP6 Drill Evaluation

a. Inspection Scope

On November 5, the inspectors observed and reviewed an emergency response facility activation drill to verify the licensee was properly classifying emergency events, making the required notifications, and making appropriate protective action recommendations in accordance with licensee procedures 91001-C, Emergency Classification and

Implementing Instructions; 91002-C, Emergency Notifications; and 91305-C, Protective Action Guidelines. The drill involved a simulated fuel handling accident, a steamline break inside containment followed by a steam generator tube rupture, and a radioactive release to the environment. Additionally, the inspectors attended a post-drill critique to verify that performance weaknesses and improvements were identified.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator (PI) Verification

a. Inspection Scope

The inspectors sampled licensee submittals for the PIs listed below to verify the accuracy of the PI data reported during the indicated period. The PI definitions and guidance contained in procedures 00163-C, NRC Performance Indicator Preparation and Submittal; 50025-C, Reporting of Mitigating System Performance Indicator Unavailability; and NEI 99-02, Regulatory Assessment Indicator Guideline, Rev. 2, were used to verify the basis in reporting for each data element.

Mitigating Systems Cornerstone
- High Head Safety Injection
- Residual Heat Removal

The inspectors reviewed operator log entries, maintenance rule database, monthly operating reports, monthly PI Summary reports and NRC inspection reports for PI data submitted by the licensee for Unit 1 and Unit 2 during the period from October 1, 2002, through September 30, 2003.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems

a. Inspection Scope

Daily Screening of Condition Reports. 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 either attending daily screening meetings that briefly discussed major CRs, or accessing the licensee’s computerized corrective action database and reviewing each CR that was initiated.

Annual Sample Review. The inspectors reviewed the October 22 failure of 1A MDAFW Pump to Steam Generator 4 Discharge Control Valve (DCV) 1HV5137 documented in CR 2003003157. The inspectors assessed whether the issue was identified in a timely manner; documented accurately and completely; properly classified and prioritized; adequately considered extent of condition, generic implications, common cause, and previous occurrences; adequately identified root causes; and, identified appropriate corrective actions. Also, the inspectors assessed whether the issue was processed in accordance with procedure 00150-C, Condition Reporting and Tracking System, and Nuclear Management Guideline procedure NMP-GM-002-GL02, Corrective Action Program Details and Expectations Guideline.

b. Findings and Observations

As documented in CR 2003003157, the failure involved separation of the valve's pilot plug assembly from the valve stem resulting from the failure of a cotter pin designed to secure the pilot plug assembly retaining nut to the stem. Without the cotter pin, the retaining nut unscrewed from the stem allowing the pilot plug spacer, washer, and retaining nut to separate and become lodged against the downstream flow orifice resulting in significant AFW flow reduction to the steam generator. Valve 1HV5137 is one of sixteen AFW DCVs (i.e., four MDAFW DCVs per unit and four TDAFW DCVs per unit) and are of the same manufacturer and type, i.e., Fisher Controls International, Inc., Type SS-120.

The disposition section of this CR stated that it appeared likely that cotter pin degradation existed in other AFW DCVs. This was based on a 1988 valve vendor notice alerting users of similar failures, a 1989 similar failure of AFW DCV 2HV5132, and lack of other recent or periodic internal inspection data of other AFW DCVs. An action item was initiated to inspect the remaining MDAFW DCVs during the upcoming refueling outages (Unit 2 - April 2004 and Unit 1 - March 2005) and then evaluate whether it was necessary to inspect the TDAFW DCVs.

The inspectors were concerned that the licensee had not adequately justified the continued operability of the AFW DCVs that had not been inspected. Following discussions with the licensee, the licensee initiated actions to document their operability evaluation. To support their evaluation, the Unit 1 MDAFW valves 1HV5132 and 1HV5134 were disassembled and inspected. The cotter pins on both valves were found missing; however, movement of the retaining nuts was being restricted by what appeared to be raised metal on the stem threads which was created by vibration of the cotter pins prior to their failure. Based on this condition, the licensee concluded that the Unit 2 AFW DCVs were operable. On December 23, the inspectors reviewed the licensee's completed operability evaluation and raised additional questions regarding the licensee's assumptions and justifications. On December 29, the inspectors were informed that the licensee had decided to accelerate their inspection schedule for the remaining AFW DCVs.

An unresolved item (URI) was identified to complete the review of the licensee's operability evaluation, review the results of the licensee's valve inspections, evaluate the significance of the results, and to determine if any NRC enforcement action was warranted for the identified conditions. This issue is identified as URI 05000424, 425/2003005-01: Review Results of Licensee Auxiliary Feedwater Discharge Control Valve Inspections for Previously Identified Pilot Plug Assembly Concerns.

4OA3 Event Follow-up

(Closed) Licensee Event Report (LER) 50-424/03-001-00: Debris in Containment Could Have Resulted in Safety System Loss of Function

a. Inspection Scope

The inspectors reviewed the LER and CR 2003003311, which documented the issue in the licensee's corrective action program, to verify the accuracy of the LER and the appropriateness of the corrective actions.

b. Findings

Introduction. A Green non-cited violation (NCV) was identified for an inadequately performed containment building inspection for debris which could be transported to the containment sump in the event of a design basis loss of coolant accident (LOCA).

Description. On July 28, 2003, a licensee evaluation determined that during the Unit 1 refueling outage (RFO) 1R10, debris left in containment on April 6 and 7, 2002, could have resulted in inadequate net positive suction head (NPSH) for the Residual Heat Removal (RHR) system in a post-accident recirculation configuration.

On April 7, 2002, with the unit in Mode 3, Hot Standby, the resident inspectors performed a containment closeout inspection in accordance with NRC Inspection Procedure 71111.20. The inspection was completed following the licensee's performance of a containment inspection in accordance with procedure 14900-C, Containment Exit Inspection, prior to Mode 4, Hot Shutdown. The inspectors found numerous items of debris (e.g.; rags, absorbent material, tape residue, tie wraps, etc.) that could be transported to the containment emergency sumps in the event of a design basis LOCA. The items identified were documented in CR 2002001335. The inspectors determined the condition to be a minor violation because the amount of debris that could be transported to the sump in the event of a LOCA was determined to have no impact on Containment Spray (CS) or RHR pump operation.

During the Unit 2 RFO (fall 2002), the licensee identified that the insulation on the bottom of the steam generators was not covered by a stainless steel jacket. The licensee determined that this un-jacketed insulation was not considered in the containment sump blockage calculation. The licensee evaluated this condition and determined that the insulation debris generated during a design basis LOCA would reduce the NPSH margin but would not impact either CS or RHR pump operation.

Since this condition also existed on Unit 1, the licensee evaluated the condition including the debris found inside containment by the inspectors during RFO 1R10. The licensee determined that the containment sump blockage could have caused the RHR pumps to fail due to inadequate NPSH during the recirculation phase.

Analysis. The failure to perform an adequate containment closeout inspection was greater than minor because the finding affected the equipment performance attribute of the Mitigating System Cornerstone objective of ensuring the availability, reliability and capability of systems (i.e., RHR) that respond to initiating events (such as a design basis LOCA). Since this condition could have resulted in the loss of RHR recirculation safety function, a regional Senior Reactor Analyst performed a Phase III evaluation under the Significance Determination Process (SDP) to ascertain the safety significance. The Phase III analysis only considered the LOCAs (small, medium or large) that could dislodge un-jacketed steam generator insulation. This was due to the key assumption that both the debris and the insulation, together, were necessary to cause inadequate NPSH for the RHR pumps during the recirculation phase. Using the SDP Notebook under the Phase II evaluation for the three dominant accident sequences, and after applying the appropriate adjustments to the accident sequences for the actual plant condition and exposure time, this resulted in a very low risk significance determination or Green finding. The direct cause of this finding involved the cross-cutting area of Human Performance.

Enforcement. Technical Specification 5.4.1.a requires, in part, that written procedures be implemented covering activities listed in Regulatory Guide 1.33, Revision 2, Appendix A, February 1978, which includes procedures for startup and changing modes of operation that impact emergency core cooling systems (ECCS). Technical Requirement Surveillance 13.5.1.1 requires, in part, that a visual inspection of accessible areas of containment be made prior to entry into Mode 4 from Mode 5 to verify that no loose debris (rags, trash, clothing, etc.) is present which could be transported to the containment emergency sump and cause restrictions of the pump suctions during LOCA conditions. Procedure 14900-C, Containment Exit Inspection, Rev. 9, step 5.1, states “Just prior to establishing Containment Integrity, inspect all accessible areas of containment for loose debris (rags, trash, clothing, etc.) which could be transported to the Containment Emergency Sumps.” Contrary to the above, licensee personnel performing containment closeout inspections on April 5, 2002, failed to identify loose debris that could be transported to the Containment Emergency Sumps. Because the finding is of very low safety significance and has been entered in the licensee corrective action program as CR 2003003311, this violation is being treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy: NCV 05000424/2003005-02, Failure to Adequately Perform Containment Closeout Inspection Resulted in Possible Loss of Post-Accident Recirculation Function of the Residual Heat Removal System.

4OA4 Cross Cutting Aspects of Findings

Section 4OA3 describes a finding of licensee personnel performing containment closeout inspections failing to identify loose debris that could have impacted the functionality of the ECCS in post accident recirculation. The direct cause of this finding involved the cross-cutting area of Human Performance.

4OA5 Other

1. (Open) NRC Temporary Instruction (TI) 2515/150, Rev. 2, Reactor Pressure Vessel Head and Vessel Head Penetration Nozzles (NRC Order EA-03-009) (Unit 1)

a. Inspection Scope

The inspectors reviewed the licensee's inspection activities related to the Unit 1 reactor pressure vessel (RPV) head and vessel head penetration (VHP) nozzle inspection activities in response to NRC Order EA-03-009, issued February 11, 2003. In the licensee's response to NRC Bulletin 2002-02, they calculated the effective degradation years based on time and head temperature which placed both units in the "Low Susceptibility" ranking for nozzle leakage potential. In accordance with NRC Order EA-03-009, the licensee conducted a bare metal visual examination of the Unit 1 reactor head during the current refueling outage. The inspection included interviews with visual inspection (VT) examination personnel, review of VT procedures, assessment of VT personnel training and qualifications, and observation/assessment of VT examinations. Specifically, the inspectors reviewed or observed the following:

- Observed a portion of in-process bare metal remote video VT inspection of VHP Nozzle Nos. 14, 19, 21, 24, 28, 29, 30, 37, 39, 44, 45, 51, 54, and 56 (including space around nozzle). In addition, observed a portion of the bare metal video tape and still digital pictures for selected nozzles.

- Reviewed and discussed with licensee personnel the susceptibility ranking calculation and the basis for the reactor vessel head temperatures used in the calculation.

- Reviewed licensee procedures and inspection results of visual examinations to identify potential boric acid leaks from pressure-retaining components above the reactor vessel head.

- Independently assessed the condition of the reactor vessel head by direct visual observation looking for loose debris, insulation, dirt, boron deposits, and boric acid corrosion.

b. Findings and Observations

In accordance with the requirements of TI 2515/150, the inspectors evaluated and answered the following questions:

(1) Was the examination performed by qualified and knowledgeable personnel?

Yes. The inspectors found that the VT examinations were performed by trained and ASME VT-2 Level III qualified inspection personnel. The examiners were experienced and were required to have four hours of additional specific industry developed training associated with inspecting VHPs for leakage.

(2) Was the examination performed in accordance with demonstrated procedures?

Yes. The inspectors verified that the bare metal inspections were conducted in accordance with procedures ES-MISN-V-738, Visual Examination of Reactor Vessel Head Penetrations and Base Material (Remote and Direct), 84008-C, RPV Alloy 600 Material Inspection and Reports, and 85020-C, Visual Inspection.

(3) Was the examination able to identify, disposition, and resolve deficiencies and capable of identifying the primary water stress corrosion cracking or vessel head corrosion phenomena described in NRC Order EA-03-009?

Yes. The inspectors concluded that the reactor head access, available lighting, remote imagery equipment capabilities, and procedural imagery resolution requirements were adequate to detect leakage from VHPs and identify boric acid deposits and corrosion. The visual examination was capable of identifying primary water stress corrosion cracking through evidence of leakage from a VHP.

(4) What was the condition of the reactor head?

The licensee's remote camera visual examination was conducted under the reflective mirror insulation and the as-found head condition was generally free of debris, dirt, or large boron deposits. Some slight boron surface residue was observed in various areas that the licensee believed to be from previous Conoseal connection leakage; however, this did not interfere with the examination and had not resulted in any boric acid corrosion concerns.

(6) Could small boron deposits, as described in Bulletin 2001-01, be identified and characterized?

Yes. The inspectors determined that the visual clarity and color of the video inspection process allowed for effective identification and characterization of boron deposits as described in Bulletin 2001-01.

(7) What material deficiencies were identified that required repair?

None. The licensee did not identify any leaking VHPs nor any boric acid corrosion as a result of their examinations.

(8) What impediments to effective examination were present?

None. The visual examination of the reactor head included 100% circumferential coverage of each VHP and its associated annulus region and all areas of the reactor vessel head surface except for a small inaccessible area where the control rod drive mechanism shroud support structure and reflective metal insulation meet the vessel head. This area was estimated to be less than one percent of the vessel head surface and not significant for determining if head wastage was present.

(9) What was the basis for the temperatures used in the susceptibility ranking calculation?

The licensee used 560°F as the reactor vessel head temperature for both units. Based on discussions with licensee personnel, this value was obtained from Westinghouse and was the Vogtle reactor T-cold design temperature.

(10) Did procedures exist to identify potential boric acid leaks from pressure-retaining components above the reactor vessel head?

Yes. Licensee procedures 84008-C, RPV Alloy 600 Material Inspection and Reports, 85020-C, Visual Inspection, and 14864-1/2, Containment General Leak Inspection, provided adequate instructions for conducting visual inspections during each refueling outage to identify potential boric acid leaks from pressure-retaining components above the reactor vessel head.

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

a. Inspection Scope

The inspectors reviewed the licensee's inspection activities related to the Unit 1 reactor vessel lower head penetrations in response to NRC Bulletin 2003-02, Leakage from Reactor Pressure Vessel Lower Head Penetrations and Reactor Coolant Pressure Boundary Integrity, in accordance with NRC TI 2515/152, Reactor Pressure Vessel Lower Head Penetration Nozzles (NRC Bulletin 2003-02), dated August 21, 2003. The inspection included review of VT procedures, assessment of VT personnel training and qualifications, and observation and assessment of VT examinations. Specifically, the inspectors reviewed or observed the following:

Bare Metal Visual Examination:

- Visually inspected the lower penetration nozzles and head from two locations approximately 180 degrees apart.
- Observed approximately half of the in-process bare metal remote video VT inspection.
- Reviewed pictures taken from the video inspection of the remaining half of the inspection that was not observed.

b. Findings and Observations

The inspectors found that the VT examinations were performed by trained and ASME VT-2 Level III qualified inspection personnel. The examiners were experienced and had additional training in inspecting the lower head penetrations. The inspectors verified the adequacy of procedure ES-MISN-V-738, Visual Examination of Reactor Vessel Head Penetrations and Base Material (Remote and Direct), used to conduct the examination. The inspectors verified the inspection was performed in accordance with procedures 85020-C, Visual Inspection, and 84008-C, RPV Alloy 600 Material Inspections and Reports.

The licensee performed VT examinations of all 58 nozzle penetrations and the lower head. The VT-2 inspection included inspection of 100% of the circumference of each nozzle and was capable of identifying any pressure boundary leakage as described in the bulletin and any lower head corrosion. There were no impediments identified that would impact VT examination. Based on observation of the inspection process, the inspectors concluded that deficiencies were properly identified and resolved.

The inspectors observed that the visual clarity, resolution and color of the video inspection process allowed for effective visual examination of the vessel lower head surface and 100% circumferential coverage of each head penetration and its associated annulus region. The visual inspection was capable of identifying small debris or boric acid deposits as a result of primary water stress-corrosion cracking through evidence of leakage from a penetration. No leakage was identified from any of the vessel lower head penetrations.

The examination involved a remote visual inspection and video taping of the lower reactor vessel head surface in the area of the 58 nozzles as well as the circumference of each nozzle. The inspection was conducted using a crawler mounted video camera positioned on the lower head insulation below the reactor vessel.

There were no significant examples of leakage sources, insulation, debris, dirt, or other physical impediments that prevented a complete visual examination. The vessel lower head was generally free of debris, dirt, or large boron deposits. There was evidence of some minor surface corrosion, flaking of vessel coating and staining that was caused by leakage that originated above the lower head in the vicinity of the loop 3 cold leg (documented in CR 2003002709). The licensee determined that the coating was applied to protect the vessel prior to initial plant operations and there was no need for repair. The licensee inspected the loop 3 nozzle transition region and found no visible boron residue or rust. Wet swipe samples were collected from the loop 3 cold leg nozzle area and the bottom of the vessel. The licensee determined based on isotopic analysis that the samples contained particulate with a nuclide signature similar to RWST water from 5.7 and 6.9 years ago that was used to fill the refueling cavity during the 1R6 and 1R7 refueling outages. The samples were analyzed for boron and lithium. Lithium was determined to be below detectable levels and low levels of boron were identified. Based on sample analysis and review of applicable design drawings, the licensee concluded that the rust stain was caused by refueling cavity water flowing down a cold reactor vessel originating from a leaking seal on a ventilation port. The ventilation port is temporarily sealed during refueling outages to allow reactor cavity flooding. There was no evidence of any boric acid deposits originating at the interface between the vessel and the penetrations. The licensee performed minor hand cleaning in the area of several penetrations to facilitate future inspections. The licensee has no current plans to perform any additional cleaning of the lower head. No material deficiencies were found that required repair.

3. (Closed) TI 2515/153, Reactor Containment Sump Blockage (NRC Bulletin 2003-01) (Unit 1)

a. Inspection Scope

The inspectors reviewed the licensee's activities in response to NRC Bulletin 2003-01, Potential Impact of Debris Blockage on Emergency Sump Recirculation at Pressurized Water Reactors, dated June 9, 2003. The inspection included review of the licensee's 60 day Bulletin response letter, review of interim compensatory measures implemented to reduce the potential risk due to post-accident debris blockage on emergency sump recirculation, and walkdown of the Unit 1 containment prior to restart from the current refueling outage to identify if any sources of potential debris existed that could impact the containment recirculation sump performance. The inspectors assessed whether the licensee either (1) performed a plant-specific evaluation of the emergency core cooling system (ECCS) and CS recirculation functions for impact of post-accident debris blockage effects, or (2) effectively implemented reasonable compensatory measures.

b. Findings and Observations

By letter dated August 7, 2003, the licensee responded to NRC Bulletin 2003-01 and described interim compensatory measures that had been implemented or were planned. These compensatory measures were designed to provide interim actions in order to reduce the risk which may be associated with potentially degraded or nonconforming ECCS and CSS recirculation functions until a more detailed evaluation could be completed to verify conformance with applicable regulatory requirements. The inspectors verified the following compensatory measures identified in the licensee's response had been implemented or were planned and scheduled.

(1) Operator training on indications of and response to sump clogging:

The inspectors reviewed Emergency Operating Procedure (EOP) 19111-C, ECA 1.1 Loss of Emergency Coolant Recirculation, and verified that initial and continuing operator training contained guidance associated with the procedure for dealing with a complete loss of ECCS and CSS recirculation capability. The inspectors reviewed Standing Order C-2003-5, issued by the Operations Department on July 24, 2003, which provided additional guidance to the operators emphasizing the need for continuous monitoring of ECCS recirculation plant parameters to identify degrading conditions and actions to be taken if sump blockage is encountered. Also, the inspectors verified that additional sump blockage guidance was scheduled to be provided to all licensed operators in the next continuous operator training (Segment #20041) that was commencing January 12, 2004.

(2) Procedural modifications, if appropriate, that would delay the switchover to containment sump recirculation:

The licensee determined that existing guidance contained in EOP 19111-C and the additional guidance provided in Standing Order C-2003-5 provided adequate guidance for dealing with a complete loss of sump recirculation. However, the licensee planned to review any future Westinghouse Owners Group EOP recommendations, if issued, to determine if any Vogtle specific procedural changes would be appropriate.

(3) Ensuring that alternate water sources are available to refill the RWST or to otherwise provide inventory to inject into the reactor core and spray into the containment atmosphere:

The licensee determined that no additional changes were necessary to existing plant procedures designed to refill the RWST or provide cooling to the reactor core or containment. The inspectors reviewed the following procedures and verified that they contained adequate guidance for providing alternate borated and unborated water sources to refill the RWST or inject into the reactor core and containment:

- 19111-C, ECA 1.1 Loss of Emergency Coolant Recirculation
- 13701-1/2, Boric Acid System
- Severe Accident Management Guideline 8 (SAG-8), Flood Containment

(4) More aggressive containment cleaning and increased foreign material controls:

The licensee determined that adequate procedural guidance currently existed for containment cleaning and foreign material control. The inspectors reviewed the following procedures and verified that the licensee was adequately implementing the procedures during the current Unit 1 refueling outage.

- 00254-C, Foreign Material Exclusion and Plant Housekeeping Programs
- 00303-C, Containment Entry
- 00309-C, Control of Unattended Temporary Materials in Containment in Modes 1-4
- 11864-C, Containment General Inspection Guidelines
- 12000-C, Post Refueling Operations (Mode 6 To Mode 5)
- 12001-C, Unit Heatup to Hot Shutdown (Mode 5 To Mode 4)
- 14864-1/2, Containment General Leak Inspection
- 14900-C, Containment Exit Inspection

In addition, the inspectors performed a routine walkdown of the Unit 1 containment prior to plant restart on October 20, following the licensee’s containment cleanup activities to verify that debris was not left that could affect the performance of the containment sumps. During this walkdown, the inspectors identified some materials (e.g., plastic flashlight, pens, roll of duct-tape, foam earplugs, plastic tie-wraps, and an assortment of other small paper and plastic items) that were not removed by the licensee's cleanup activities. The licensee documented these items in CR 2003003134 and subsequently determined that it would not have adversely impacted the operation of the containment sumps. Based on the results of previous inspector walkdowns of containment following refueling outages, the inspectors determined that the licensee had shown improvement in their post-refueling cleanup effectiveness.

(5) Ensuring containment drainage paths are unblocked:

The inspectors reviewed procedures 12000-C and 12001-C and verified that they contained adequate instructions for ensuring that the reactor cavity drains were properly opened prior to the plant entering Mode 4 following a refueling outage to ensure that the drainage path to the containment sump was unblocked. In addition, the inspectors verified the procedures were properly implemented during the current Unit 1 refueling outage.

(6) Ensuring sump screens are free of adverse gaps and breaches:

The inspectors reviewed procedure 14903-1/2, Containment Emergency Sump Inspection, and verified that it contained adequate guidance for identifying adverse gaps and breaches. In addition, the inspectors verified the procedure was properly implemented during the current Unit 1 refueling outage.

4. Notice of Enforcement Discretion (NOED) for TS Surveillance Requirement Extension

On November 4, the NRC verbally granted a Unit 2 NOED related to enforcing compliance with the requirements of TS Surveillance Requirement (SR) 3.3.1.5 and 3.3.2.2 for the SSPS that was required to be completed by November 5. On October 26, the licensee was unable to complete portions of the SSPS testing due to malfunction of a SSPS test switch. The licensee requested a 28 day extension to the surveillance interval in order to process an exigent TS amendment allowing the testing to be completed after replacing the test switch during the next refueling outage. The details of the NOED and TS amendment requests were documented in a licensee letter dated November 5. The NRC granted the NOED in a letter dated November 7. The inspectors reviewed the applicable TS requirements, assessed the impact of the uncompleted portion of the testing, and monitored the licensee's compliance with compensatory measures established as conditions for granting of the NOED. No issues were identified from these reviews. A URI will be identified to review the root cause of the test switch failure and to determine if NRC Enforcement Actions are warranted for the identified condition. This issue is identified as URI 05000425/2003005-03: NOED for Extension of Portions of Unit 2 SSPS TS Surveillance Testing.

4OA6 Meetings, Including Exit

On January 9, 2004, the resident inspectors presented the inspection results to Mr. W. Kitchens and other members of his staff, who acknowledged the findings. The inspectors confirmed that proprietary information was not provided or examined during the inspection.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee personnel:

W. Bargeron, Plant Support Assistant General Manager
W. Burmeister, Manager Engineering Support
D. Carter, Superintendent Chemistry
J. Dixon, Superintendent Health Physics
S. Douglas, Manager Operations
K. Holmes, Manager Training and Emergency Preparedness
W. Kitchens, Nuclear Plant General Manager
I. Kochery, Health Physics & Chemistry Manager
T. Tynan, Assistant General Manager Operations

Other licensee employees contacted included office, operations, engineering, maintenance, chemistry/radiation, and corporate personnel.

NRC personnel:

B. Bonser, Chief, Reactor Project Branch 2
W. Rodgers, Senior Risk Analyst

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000424, 425/2003005-01	URI	Review Results of Licensee Auxiliary Feedwater Discharge Control Valve Inspections for Previously Identified Pilot Plug Assembly Concerns (Section 4OA2.2)
05000425/2003005-03	URI	NOED for Extension of Portions of Unit 2 SSPS TS Surveillance Testing (Section 4OA5.4)

Opened and Closed

05000424/2003005-02	NCV	Failure to Adequately Perform Containment Closeout Inspection Resulted in Possible Loss of Post-Accident Recirculation Function of the Residual Heat Removal System (Section 4OA3)
2515/152 (Docket 50-424)	TI	Reactor Pressure Vessel Lower Head Penetration Nozzles (NRC Bulletin 2003-02) (Section 4OA5.2)
2515/153 (Docket 50-424)	TI	Reactor Containment Sump Blockage (NRC Bulletin 2003-01) (Section 4OA5.3)

Discussed

2515/150 (Docket 50-424)	TI	Reactor Pressure Vessel Head and Vessel Head Penetration Nozzles (NRC Order EA-03-009) (Section 4OA5.1)

LIST OF DOCUMENTS REVIEWED

Section 1R01: Adverse Weather
Procedures
11877-1/2, Cold Weather Checklist
11901-1/2, Heat Tracing System Alignment
13150-1/2, Nuclear Service Cooling Water System
13901-1/2, Heat Tracing System
17104-1/2, Annunciator Response Procedures for Heat Tracing Panel 1(2)NCQARHT
50050-C, Heat Tracing Program

Section 1R04: Equipment Alignment
Procedures
11405-2, 125V DC 1E Electrical Distribution System Alignment
13405-2, 125V DC 1E Electrical Distribution System
11610-1, Auxiliary Feedwater System Alignment
13610-1, Auxiliary Feedwater System

Section 1R05: Fire Protection
Procedures
92820-2, Zone 120 - Control Building - Level 2 Fire Fighting Preplan
92855-2, Zone 155 - Auxiliary Feedwater Pumphouse - Train B Fire Fighting Preplan
92856-2, Zone 156 - Auxiliary Feedwater Pumphouse - Fire Fighting Preplan
92857A-2, Zone 157A - Auxiliary Feedwater Pumphouse - Train C Fire Fighting Preplan
92804-2, Zone 104 - MSIV Room North Level 1 Fire Fighting Preplan
92856-1, Zone 156 - Auxiliary Feedwater Pumphouse - Fire Fighting Preplan
92857A-1, Zone 157A - Auxiliary Feedwater Pumphouse - Train C Fire Fighting Preplan
92719-2, Zone 19 - Auxiliary Building - CVCS Centrifugal Charging Pump Rooms - Fire Fighting Preplan
92753-2, Zone 53 - Auxiliary Building - Level 2, AB Normal HVAC Units Fire Fighting Preplan
92754-2, Zone 54 - Auxiliary Building - Level 2, Train “A” CCW HX Fire Fighting Preplan
92755-2, Zone 55 - Auxiliary Building - Level 2, Train “B” CCW HX Fire Fighting Preplan
92847-2, Zone 147 - Auxiliary Building - Level 2, Fire Fighting Preplan
92745-1, Zone 45 - Auxiliary Building - Level 1 Fire Fighting Preplan

Section 1R06: Flood Protection
Procedures
11889-C, Severe Weather Checklist
11219-1, Auxiliary and Containment Buildings and Miscellaneous Drain Systems Alignment

Design Documents
DC-1203, Component Cooling Water System

DC-1003, Flooding - Interdiscipline
DC-1214, Containment and Auxiliary Building Drain System - Radioactive
DC-1206, Containment Spray System
DC-1215, Auxiliary Building Drain System - Nonradioactive
DC-1218, Auxiliary Building Flood-Retaining Rooms, Alarms, and Drains

CRs
2003001591, 2003002599, 2003001271, 2003001731, 2003000274, 2003000929, 2002003391, 2003002116, 2003002119, 2003002195, 2003002105, 2002000134, 2003002501, 2002003356, 2003001249

Section 1R20: Refueling and Outage Activities

Procedures
00254-C, Foreign Material Exclusion and Plant Housekeeping Programs
00309-C, Control of Unattended Temporary Material in Containment in Modes 1-4
11899-2, RCS Draindown Configuration Checklist
12000-C, Post Refueling Operations (Mode 6 to Mode 5)
12001-C, Unit Heatup to Hot Shutdown (Mode 5 to Mode 4)
12002-C, Unit Heatup to Normal Operating Temperature and Pressure
12003-C, Reactor Startup (Mode 3 to Mode 2)
12004-C, Power Operations (Mode 1)
12005-C, Reactor Shutdown to Hot Standby (Mode 2 to Mode 3)
12006-C, Unit Cooldown to Cold Shutdown
12007-C, Refueling Operations (Entry into Mode 6)
13005-2, Reactor Coolant System and Refueling Cavity Draining
14210-2, Containment Building Penetrations Verification - Refueling
14406-2, Boron Injection Flow Path Verification - Shutdown
14900-C, Containment Exit Inspection
18004-C, Reactor Coolant System Leakage
18019-C, Loss of Residual Heat Removal
18030-C, Loss of Spent Fuel Pool Level or Cooling
27504-C, Equipment Hatch Emergency Closure
23985-2, RCS Temporary Water Level System
29540-C, Risk Assessment Monitoring
29542-C, Shutdown Risk Management
93300-C, Conduct of Refueling Operations
93663-C, Verification of Core Loading Pattern

Other Documents
LPPT-GAE/GBE-01, Low Power Physics Test Program with Dynamic Rod Worth Measurement