May 2, 2005

Mr. George Vanderheyden
Vice President - Calvert Cliffs Nuclear Power Plant
Constellation Generation Group, LLC
1650 Calvert Cliffs Parkway
Lusby, Maryland 20657-4702

SUBJECT: CALVERT CLIFFS NUCLEAR POWER PLANT - NRC INTEGRATED INSPECTION REPORT 05000317/2005002 AND 05000318/2005002

Dear Mr. Vanderheyden:

On March 31, 2005, the US Nuclear Regulatory Commission (NRC) completed an inspection at your Calvert Cliffs Nuclear Power Plant Units 1 and 2. The enclosed integrated inspection report documents the inspection findings, which were discussed on April 14, 2005, with Mr. Dave Holm 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 two NRC-identified findings of very low safety significance (Green), both of which were determined to involve a violation of NRC requirements. However, because of the very low safety significance and because these issues were entered into your corrective action program, the NRC is treating these findings as non-cited violations (NCV) consistent with Section VI.A of the NRC Enforcement Policy. Additionally, a licensee-identified violation which was determined to be of very low safety significance is listed in Section 4OA7 of this report. If you contest any 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 U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, D.C. 20555-0001, with copies to the Regional Administrator, Region 1; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, D.C. 20555-0001; and the NRC Resident Inspector at Calvert Cliffs.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter and 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 the NRC's document system (ADAMS). ADAMS is accessible from the NRC Web Site at http://www.nrc.gov/reading-rm.html (the Public Electronic Reading Room).

Sincerely,

/RA/

James M. Trapp, Chief
Projects Branch 1
Division of Reactor Projects

Docket Nos. 50-317, 50-318
License Nos. DPR-53, DPR-69

Enclosure: Inspection Report 05000317/2005002 and 05000318/2005002 w/Attachments

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REGION I

Docket Nos.	50-317, 50-318
License Nos.	DPR-53, DPR-69
Report Nos.	05000317/2005002 and 05000318/2005002
Licensee:	Constellation Generation Group, LLC
Facility:	Calvert Cliffs Nuclear Power Plant
Location:	1650 Calvert Cliffs Parkway Lusby, MD 20657-4702
Dates:	January 1, 2005 - March 31, 2005
Inspectors:	Mark A. Giles, Senior Resident Inspector Joseph M. O'Hara II, Resident Inspector Jack McFadden, Health Physicist Harold Gray, Senior Reactor Inspector James Krafty, Reactor Inspector Anne Passarelli, Reactor Inspector Nancy McNamara, Emergency Preparedness Inspector
Approved by:	James M. Trapp, Chief Projects Branch 1 Division of Reactor Projects

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SUMMARY OF FINDINGS

IR 05000317/2005002, 05000318/2005002; 01/01/2005 - 03/31/2005; Calvert Cliffs Nuclear Plant, Units 1 and 2; Equipment Alignment, Operability Evaluations and Cross-Cutting Areas.

The report covered a three-month period of inspection by resident inspectors and announced inspections performed by a senior reactor inspector, a health physicist, two reactor inspectors, and an emergency preparedness inspector. The inspection identified two Green findings, which were determined to be non-cited violations. 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 Technical Specification 5.4.1.a. "..., written procedures shall be established, implemented,.." because plant procedural requirements were not implemented while performing maintenance on the Unit 2, 21A reactor coolant pump (RCP) drain line valve replacement activity during reduced inventory. Specifically, on March 7, 2005, while in reduced reactor coolant system (RCS) inventory, the 21A RCP drain line was opened to support a maintenance activity which inadvertently drained the RCS into the normal containment sump. The RCS level dropped one-half inch before operators diagnosed the draindown and closed the drain valve. A lack of knowledge and understanding regarding the height of the drain line penetrating into the RCS piping, as compared to the reduced inventory level of the RCS, resulted in the inadvertent draindown and loss of RCS inventory.

  This finding is greater than minor because it was associated with the Initiating Events Cornerstone configuration control attribute and affected the cornerstone's objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown operations. This finding did not involve an actual loss of shutdown cooling (SDC). As a result, this finding was determined to be of very low safety significance (Green) in accordance with a Phase 2 risk assessment performed using the NRC Inspection Manual, Chapter 0609, "Significance Determination Process," Appendix G, "Shutdown Operations Significance Determination Process." The inspectors identified that a contributing cause of this finding was related to the cross-cutting area of human performance. The relevant causal factor was personnel because licensed operators did not follow plant procedures and determine if boundaries specified in the clearance order were adequate for the maintenance activity. (Section 1R04)

Cornerstone: Mitigating Systems

- Green. The inspectors identified a non-cited violation of Technical Specification 5.4.1.a. "..., written procedures shall be established, implemented,.." because plant procedural requirements were not included in all appropriate sections of the Unit 1 Operating Instruction, OI-15, "Service Water System." Specifically, certain procedural sections in OI -15 did not adhere to OI-15 precaution L, which prohibited the system to be in a configuration where two service water pumps could have loaded simultaneously onto a single emergency diesel generator (EDG). An engineering evaluation performed by the licensee, associated with the two pumps simultaneously loading onto an EDG, determined that this system alignment could have adversely affected the reliability of the safety-related Fairbanks Morse EDG following a loss of offsite power (LOOP) event concurrent with a loss of coolant accident (LOCA).

  This finding is greater than minor because it was associated with the Mitigating System Cornerstone human performance attribute and affected the cornerstone's objective of ensuring the availability, reliability, and capability of systems that respond to initiating events. This finding did not involve the actual loss or degradation of equipment specifically designed to mitigate a seismic event or the loss of any safety function. As a result, this finding was determined to be of very low safety significance (Green) in accordance with a Phase 1 risk assessment performed in accordance with Inspection Manual Chapter - 0609, "Significance Determination Process." The inspectors identified that a contributing cause of this finding was related to the cross-cutting area of human performance. The relevant causal factor was personnel because the Unit 1 service water procedures were not appropriately changed by operations procedure writers although a procedure revision was noted in the modification package as being required. (Section 1R15)

B. Licensee-Identified Violations

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

REPORT DETAILS

Summary of Plant Status

Unit 1 began the inspection period at 100 percent reactor power and remained unchanged until February 28, when reactor power was reduced to support scheduled piping repairs on the 11 moisture separator reheator drain tank vent piping. During the power reduction, vibrations associated with the Unit 1 main turbine generator steadily increased to the point that a manual reactor trip was performed in accordance with approved station procedures at approximately 15 percent reactor power. Following piping repair activities, reactor power was increased to 100 percent on March 2, where it remained unchanged for the rest of the inspection period.

Unit 2 began the inspection period at 100 percent reactor power and remained unchanged until February 4, when the licensee began a coastdown power reduction to support a scheduled Unit 2 refueling outage (RFO). The reactor power reduction was stopped on February 17, at 93 percent to support main steam safety valve testing. Following the completion of testing, reactor power was reduced from 93 percent to 0 percent to support the RFO. Subsequent to the RFO, the unit was restored to 100 percent reactor power on March 17. On March 18, Unit 2 reactor power was reduced from 100 percent reactor power to 94 percent reactor power due to an erroneous high differential pressure indication associated with the 22A/B traveling screens. The licensee determined that a differential pressure transmitter had failed and caused the erroneous reading. The unit was restored to 100 percent reactor power the same day where it remained unchanged for the rest of the inspection period.

1. REACTOR SAFETY

Cornerstone: Initiating Events, Mitigating Systems, Barrier Integrity

1R01 Adverse Weather Protection (71111.01 - 1 sample, Impending Weather)

a. Inspection Scope

On January 14, 2005, the licensee entered ERPIP 3.0, “ Immediate Actions,” for a severe weather and tornado watch. While no tornados were observed at the site, the storm produced severe rain conditions. The inspectors were present in the control room when operators received a “Unit 1 Main Generator Field Ground” annunciator alarm. The licensee had left a rollup door opened and rain water had entered the Turbine Building which caused the alarm. The inspectors reviewed the adverse weather preparations and mitigating strategies for severe weather events. This review included an assessment of Emergency Response Plan Implementation Procedure (ERPIP) 3.0, “Immediate Actions,” Attachment 20, “Severe Weather,” ERPIP 3.0, “Immediate Actions,” Attachment 21, “Personnel Recall for Severe Weather,” and Operations Administrative Policy OAP 00-01, “Severe Weather Operations.”

The inspectors chose the 12 condensate storage tank (CST), a risk significant system, for a more detailed inspection. This system was selected because rainwater entering the Turbine Building had significantly wetted the exterior of a junction box which contained safety-related CST level instrumentation cabling. However, since no rainwater entered into the junction box, there were no adverse consequences. The inspectors conducted discussions with control room operators and system engineers to understand protective features applicable to this system, and performed a partial field walkdown of the system to verify severe weather protection mitigating strategies and measures were functioning properly subsequent to the event.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment

1. Partial System Walkdown. (71111.04Q - 7 samples)

a. Inspection Scope

The inspectors verified that selected equipment trains of safety-related and risk significant systems were properly aligned. The inspectors reviewed plant documents to determine the correct system and power alignments, as well as the required positions of critical valves and breakers. The inspectors verified that the licensee had properly identified and resolved equipment alignment problems that could cause initiating events or potentially impact the availability of associated mitigating systems. The applicable documents used for this inspection are located in the Attachment. The inspectors performed the following partial system walkdowns:

- 21A reactor coolant pump (RCP) maintenance draindown alignment
- Unit 1 boric acid storage tank/boric acid system alignment during relief valve removal and reinstallation
- Unit 2 component cooling (CC) water system alignment while cleaning 22 CC heat exchanger
- 2A EDG during and following the repair of a jacket cooling water leak
- Unit 2 4 KV alternate feeder alignment to prevent a dual unit trip in the event of a loss of transformer P-13000-1
- 21 Auxiliary Feedwater (AFW) train during 21 AFW pump testing
- Unit 1 Service Water System (SRW) pump alignment during pump configuration changes

b. Findings

Introduction. The inspectors identified a Non-Cited Violation (NCV) of very low safety significance (Green) for the licensee’s failure to establish adequate physical boundaries when draining piping to support maintenance involving the replacement of drain valves associated with the 21A RCP. As a result, reactor coolant system (RCS) inventory was advertently decreased which could have degraded the shutdown cooling (SDC) system. This event occurred because the licensee did not adhere to requirements contained in station procedure NO-1-112, “Safety Tagging,” as required by Appendix “A” of Regulatory Guide 1.33, Revision 2, February 1978.

Description. On May 20, 2004, an operations department planner reviewed a maintenance order to replace low point drain valves 2HVRC-139 & 140 associated with the 21A RCP. During this review, the planner determined that a RCS level at or below 38 feet 6 inches was necessary to support this maintenance activity. Based on this information, the planner concluded that reduced inventory, RCS level below 38 feet, would be appropriate to support this maintenance activity. Two licensed operators reviewed the clearance order for this maintenance activity on January 5, 2005, and authorized the tagout. Prior to hanging the tagout, the licensee’s tagging department re-examined the maintenance order, but could not determine from piping schematics the level where the drain lines penetrated the RCS piping. The licensee’s engineering department was asked to evaluate the schematics, but similarly could not determine the associated level. While engineering was evaluating the schematics, licensed operators approved the tagout for implementation on March 7, 2005, and allowed the maintenance to proceed. At that time, there was not adequate confirmation of the level where the drain line entered the RCS, or an appropriate evaluation of the potential impact on RCS level. Because of the uncertainty surrounding this work, the licensee established a compensatory measure which was to have an operator visually observe the drain lines to confirm that there was no RCS flow once the drain valves were opened.

On March 17, 2005, operators opened 2-RC-1097 and 2-RC-1098, low point header drain valves, to drain the associated piping in preparation of the maintenance activity. Some flow was initially observed which the operator believed to be residual water in the piping, but the flow quickly stopped. After waiting approximately 20 minutes, the designated watch on the drain line concluded that the level in the RCS was below the drain valves and left the area. A short time later, a HI Containment Sump Level alarm was received in the control room. The containment watch was requested to re-enter containment and evaluate the RCS level locally and observe the 21A RCP drain line to see if RCS inventory was being drained. The containment watch informed control room operators that RCS level was being decreased by flow from the drain valve. As directed, the containment watch shut the drain valve terminating the draindown event. During subsequent discussions with the inspectors, the licensee indicated that the drain line may have been initially blocked due to either sludge or crystalized boric acid. When this blockage cleared, RCS inventory began draining through those valves. During this event, RCS level decreased roughly one-half inch to 37 feet 5 inches, which equated to about 150 gallons.

At the time this event occurred, shutdown cooling (SDC) was being provided by one low pressure safety injection (LPSI) train from the RCS. The licensee’s procedure AOP-3B, “Abnormal Shutdown Cooling Conditions,” directs operators to shut off LPSI pumps and put them in a Pull-to-Lock position if the RCS inventory lowers to 36 feet 9 inches which is eight inches below the RCS level at the time of this event. This procedural step ensures that vortexing of the LPSI pumps does not occur. The inspectors learned that the 21A RCP drain line penetrated the RCS at the 36 foot level. The inspectors determined that since the open drain lines could have reduced the RCS inventory to 36 feet, the SDC system's reliability was affected, and ultimately could have been lost if no operator action had been performed. At the time this event occurred, the estimated time to boil was 35 minutes. The licensee documented this human performance deficiency in their corrective action program as IRE-003-997.

Analysis. The inspectors determined that the licensee's failure to properly follow approved station procedures and adequately ensure that the clearance boundary for RCS level was adequate to support the maintenance was a performance deficiency. Specifically, NO-1-112, "Safety Tagging," stated that reviews of the clearance stubs shall ensure that clearance controls (especially boundaries) that have been, or are to be set by the associated clearance orders indicated on the stub, are adequate for the work to be performed under the stub. The licensee determination that a RCS level of less than 38 feet 6 inches was sufficient to support the planned maintenance activities was inadequate.

Traditional enforcement does not apply for this finding because it did not have any actual safety consequences or potential for impacting the NRC's ability to perform its regulatory function nor was it the result of any willful violation of licensee or NRC requirements.

This finding is greater than minor because it was associated with the Initiating Events Cornerstone configuration control attribute and affected the cornerstone's objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown operations.

The significance of this finding was determined by using the Shutdown Operations Significance Determination Process (IMC 0609, Appendix G).

A Phase 1 screening of the finding was performed using Appendix G and the Attachment 1 checklists. The finding resulted in an inadvertent loss of RCS inventory while in reduced inventory condition, with a level change of less than 2 inches. Therefore, this finding was not considered a "Loss of Control" as defined in Appendix G. Attachment 1, Checklist 3, "PWR Cold Shutdown and Refueling Operation - RCS Open and Refueling Cavity Level < 23 feet Or RCS Closed and No Inventory in Pressurizer Time to Boiling < 2 Hours" was used to screen this finding. The finding affected Item II.B(3), "training procedures and administrative controls implemented to avoid operations that could lead to perturbations in RCS level control or DHR flow," and increased the likelihood of a loss of RCS level control or LPSI flow control during midloop operations such that the likelihood of a loss of suction to the LPSI pumps due to air entrainment was increased. Therefore the finding required a Phase 2 analysis.

Since the finding did not involve low temperature overpressure protection, nozzle dams, or boron dilution, Appendix G, Attachment 2, "Phase 2 SDP Template for PWR During Shutdown," was used to perform a Phase 2 evaluation. This finding was considered a "Precursor Finding" because it had the potential to cause a loss of the operating train of SDC. "Loss of Inventory (LOI)" was the appropriate initiating event for this analysis because the finding actually caused a loss of reactor coolant system inventory that could have resulted in a loss of LPSI pump suction. The finding occurred when the reactor coolant system was in midloop conditions, approximately 14 days after shutdown, and after refueling activities had been completed. These conditions correlated to the Late Time Window (TW-L) of Plant Operating State 2 (POS 2) in the SDP. The “time-to-boil” was calculated by the licensee as 35 minutes. Table 8 of the SDP was used to estimate that the time-to-core uncovery and time-to-core damage were approximately 220 minutes, and 7 hours, respectively. Based on these assumptions, it was appropriate to use Table 3, “Initiating Event Likelihood (IELs) for LOI Precursors,” and Worksheet 6, “SDP for a PWR Plant - Loss of Inventory in POS 2 (RCS Vented),” to continue the Phase 2 evaluation.

The rate of unexpected loss of reactor coolant inventory was small (estimated less than 5 gpm) and would have required a long time (estimated greater than 10 hours) of undetected draining to cause a loss of SDC suction. Reactor coolant system level instrumentation was available and provided accurate indication of actual level to the control room operators. Shutdown cooling flow indication and motor current information were also available to the control room operators. As demonstrated during the event, operations personnel identified the leak path from monitoring sump level changes and demonstrated they were readily capable of identifying the leak path within ½ of the time required to cause a loss of SDC suction. Finally, the drain path was isolable by closing one valve that did not result in isolation of shutdown cooling suction. Using these assumptions, Table 3 identified that the IEL for this finding was 4.

The analyst reviewed the top event functions, equipment success criteria, and important instrumentation identified in Worksheet 6 to determine appropriate equipment credits to evaluate the core damage sequences. In addition, core exit thermocouples, shutdown cooling system temperature instrumentation, flow instrumentation, refueling water tank level instrumentation, and appropriate alarms were also available to the control room operators. Several pumps were available to provide backup makeup capability to the RCS including the high-pressure safety injection pumps and charging pumps. No conditions were identified that would result in reducing operator action credits for any of the top event functions. Based on these assumptions, the equipment credit met or exceeded the operator action credit for each top event function. Therefore, the credit for each top event function was assigned the default operator credit rating.

No credit is given in a Phase 2 analysis for operator recovery of a top event function. Therefore, quantification of each of the core damage scenarios in Worksheet 6 was performed by summing the IEL and mitigation credits for each top event function. This resulted in two sequences with a result of 9 and one sequence with a result of 8. The most significant core damage scenario involved the loss of inventory event in conjunction with failure to initiate injection into the RCS prior to core damage. In accordance with the “Counting Rule Worksheet” of IMC 0609, Appendix A, the total increase in core damage frequency associated with this finding due to internal initiating events was less than 1E-7/year. Therefore, no screening for potential risk contribution due to external initiating events or large early release frequency was required. This was a finding of very low safety significance (Green).

The inspectors identified that a contributing cause of this finding was related to the cross-cutting area of human performance. The relevant causal factor was personnel because licensed operators did not follow plant procedures and determine if boundaries specified in the clearance order were adequate for the maintenance activity.

Enforcement. Technical Specifications 5.4.1.a requires, in part, that written procedures shall be established, implemented, and maintained covering the applicable procedures recommended in Appendix “A” of Regulatory Guide 1.33, Revision 2, February 1978. Specifically, Regulatory Guide 1.33, Appendix “A”, Section 9, Procedures for Performing Maintenance, includes procedures for properly preplanning and performing maintenance that can affect the performance of safety-related equipment. Contrary to this requirement, the licensee did not properly follow approved station procedures and adequately ensure that the clearance boundary for RCS level was appropriate to support the maintenance which is required by NO-1-112, “Safety Tagging,” which stated that reviews of the clearance stubs shall ensure that clearance controls (especially boundaries) that have been, or are to be set by the associated clearance orders indicated on the stub, are adequate for the work to be performed under the stub. Because the failure is of a very low safety significance and has been entered into the corrective actions program as IRE-003-997, this violation of TS 5.4.1.a is being treated as an NCV consistent with Section VI.A.1 on NRC Enforcement Policy: **NCV05000318/2005002-01**, Failure To Establish Adequate Clearance Order Boundaries.

2. Complete System Walkdown (71111.04S - 1 sample)

a. Inspection Scope

The inspectors performed a complete system walkdown of the Unit 1 service water system (SRW), a safety-related and risk significant system. The walkdown was conducted to identify any discrepancies between the existing equipment alignment and the required alignment. The inspectors determined the correct system lineup using OI-15, Attachment 1, “Service Water Valve Alignment,” Attachment 2, “Service Water Instrument Valve Alignment,” and the appropriate piping and instrument drawings. In addition, the inspectors reviewed temporary modifications, maintenance rule status, operator workarounds, and outstanding maintenance work requests and historical deficiencies that could potentially affect the ability of the system to perform its design basis function and to assess overall system health. During this inspection the inspectors verified the following: valves were correctly positioned; electrical power was available as required; labeling was correct; hangers and supports were correctly installed and functional; support systems were operational; valves required to be locked were properly locked; and there were no objects located such that they would interfere with system operability. Minor issues identified were provided to system engineering personnel.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05Q - 9 samples)

Fire Area Walkdowns

a. Inspection Scope

The inspectors walked down accessible portions of the plant to assess the licensee's control of transient combustible material and ignition sources, fire detection and suppression capabilities, fire barriers, and related compensatory measures when required. The inspectors assessed the material condition of fire protection suppression and detection equipment to determine whether any conditions or deficiencies existed which could impair the availability of that equipment. The inspectors also reviewed administrative procedure SA-1-100, "Fire Prevention," during the conduct of this inspection. The inspectors toured the following areas important to reactor safety:

- Unit 1 cable spreading room
- Unit 2 cable spreading room
- Unit 1 27' elevation switchgear room
- 2A emergency diesel generator room
- Unit 1 west penetration room
- Unit 2 west penetration room
- 1A emergency diesel generator room
- Unit 2 AFW pump room
- 1A EDG fire system zone

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection (71111.08 - 4 Samples)

a. Inspection Scope

The inspection assessed the effectiveness of the licensee's program for monitoring degradation of the reactor coolant system boundary. The inspection focused on three activities: steam generator eddy current testing, the dissimilar metal weld inspection program, and the boric acid corrosion control inspection program. At the time of the inspection, no inspection samples involving indications left in-service were available for review.

For the steam generator eddy current inspection, the inspector reviewed the inspection scope with the analysts to determine if the goals of the inspection were applicable to the degradation assessment analysis. The inspector reviewed certification records to verify the analysts were adequately qualified to analyze the eddy current data. Also, the inspector reviewed examination procedures to determine if they provided adequate guidance and acceptance criteria to implement the examination plan. Eddy current data for wear by foreign objects just above the tube sheet and by anti-vibration bars in the U-bend area was reviewed.

For the dissimilar metal weld examination, the inspector conducted interviews with the ultrasonic (UT) and visual (VT) examination personnel and engineering personnel to assess the planning and preparation for the activities. The inspector reviewed training and qualification records to verify the licensee's personnel qualification process adequately prepared the assigned staff to perform the examination. The examination procedure was reviewed to determine whether it provided adequate guidance and examination criteria to implement the examination plan. The inspector witnessed the calibration of the ultrasonic equipment and the demonstration of the procedure on a mock-up with built-in flaws similar to that expected in the materials to be examined to verify the UT equipment as calibrated would be able to find and accurately characterize flaws on the examined welds. Inspection documents were reviewed for indications that required corrective action.

For the UT indications found in the 22A cold leg to letdown piping, the inspector reviewed the weld overlay repair design. The engineering and welding personnel involved with the repair were interviewed and the welding procedure and work package were reviewed. The inspector observed the overlay repair mock-up to verify the overlay procedure was adequate.

The inspector assessed the ability of the licensee's inspection activities to identify boric acid corrosion and leaks. The licensee's boric acid inspection procedure was reviewed to determine if it provided adequate scope and guidance on examination criteria and corrective action required when boric acid deposits were found. The inspector conducted a boric acid walkdown of containment to verify that there were no active boric acid leaks and reviewed the licensee's boric acid walkdown report for indications of active boric acid leaks or boric acid corrosion of carbon steel components.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12Q - 4 samples)

a. Inspection Scope

The inspectors reviewed the licensee's effectiveness in performing routine maintenance activities. This review included an assessment of the licensee's practices pertaining to the identification, scoping, and handling of degraded equipment conditions, as well as common cause failure evaluations, and the resolution of historical equipment problems. For those systems, structures, and components (SSC) scoped in the maintenance rule per 10 CFR 50.65, the inspectors verified that reliability and unavailability were properly monitored and that 10 CFR 50.65 (a)(1) and (a)(2) classifications were justified in light of the reviewed degraded equipment condition. The inspectors conducted this inspection for the following equipment issues:

- 2A EDG jacket cooling water leak through cracked compression fitting
- 13kV (21 Bus) to 4kV (14 Bus) voltage regulator oil level indicator failure
- 2B EDG air start compressor found tripped
- Crosby relief valve recurring test failures

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessments and Emergent Work Control (71111.13 - 4 samples)

a. Inspection Scope

The inspectors reviewed the licensee's assessments concerning the risk impact of removing from service those components associated with the work items listed below. This review primarily focused on activities determined to be risk significant within the maintenance rule. The inspectors compared the risk assessments and risk management actions performed by station procedure NO-1-117, "Integrated Risk Management," to the requirements of 10 CFR 50.65(a)(4), the recommendations of NUMARC 93-01, Revision 2, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," Section 11, "Evaluation of Systems to Be Removed From Service," and approved station procedures. The inspectors compared the assessed risk configuration to actual plant conditions to evaluate whether the assessment was accurate and comprehensive. In addition, the inspectors assessed the adequacy of the licensee's identification and resolution of problems associated with maintenance risk assessments and emergent work activities. The inspectors reviewed the following selected work activities:

- 11 saltwater header flow indicator replacement
- 21 containment air cooler fan cooler motor replacement
- 22 containment air cooler fan cooler motor replacement
- 23 HPSI pump breaker, motor, controls inspection

b. Findings

No findings of significance were identified.

1R14 Operator Performance During Non-Routine Evolutions and Events (71111.14 - 5 samples)

a. Inspection Scope

1. Unit 2 Inadvertent Spent Fuel Pool Sluicing Event

The inspectors assessed operator performance associated with a Unit 2 event that involved the inadvertent drain down of the spent fuel pool (SFP). At 7:00 a.m. on

February 18, 2005, both the SFP and the refueling pool (RFP) were at a level of approximately 67 feet. The Unit 2 reactor operators began to drain down the RFP to 63 feet to support preplanned outage activities. Following the draindown of the RFP to 63 feet at 7:50 a.m., the RFP level slowly began to rise. The operators continued to drain the RFP to maintain the level at 63 feet. At 9:22 a.m. operators received a “SFP Low Level” alarm, and initiated AOP-6F, “Spent Fuel Pool Cooling System Malfunction”, for a decreasing SFP water level. Operators began checking the positions of valves to verify the alignment of the spent fuel cooling system as directed by the control room shift manager. Through these actions, the licensee discovered that the 11 SFP cooler outlet throttle (SFP-155), cross-connect valve between the RFP and the SFP, was approximately one and one-half turns open rather than the appropriate closed position. The valve was shut terminating the level transient.

The inspectors noted that the lowest level the SFP reached during the event was 66 feet, 6 inches. The lowest level which the SFP could have reached due to the designed siphon breaks was 65 feet, 3 inches. As a result, the inspectors determined that this lower SPF level would ensure that the Technical Specification requirement to maintain the SPF level at 21 feet, 6 inches above the fuel assemblies would be maintained. The inspectors learned that the procedure that gave instructions to close the SFP-155 valve, which isolates the RFP from the SFP, was implemented before the sluicing event occurred. The root cause for the valve not being fully shut could not be definitively determined.

2. Unit 2 Inadvertent Draindown Of The RCS During 21A RCP Maintenance

The inspectors assessed operator performance associated with a Unit 2 event that involved the inadvertent draindown of the RCS while in reduced inventory. On March 7, 2005, operators opened drain valves associated with the 21A RCP drain line to support maintenance activities. The drain line penetrated the RCS piping at an elevation below the established reduced inventory RCS level, which was not understood by the licensee at the time the drain valves were opened. Opening of the drain valves resulted in an inadvertent draindown in RCS level of approximately one-half inch before operators were able to appropriately diagnose and terminate the event. (See Section 1R04)

3. Unit 1 Reactor Trip

On March 1, 2005, the Unit 1 reactor was manually tripped from 15 percent reactor power. The inspectors were present in the control room and monitoring control room operations associated with a scheduled reduction in reactor power to support piping repairs on the 11 MSR drain tank vent piping at the time of the reactor trip. The inspectors assessed plant response and conditions specific to the event and evaluated the performance of licensed operators. The inspectors determined that once trip criteria for excessive turbine vibrations was met, a manual reactor trip was ordered and performed in accordance with AOP-7E, “Main Turbine Malfunction.” An automatic Unit 1 main turbine trip immediately resulted in accordance with design following the reactor trip. The inspectors observed control room activities and procedures, and reviewed operator logs to determine if operators performed the appropriate actions in accordance with their training and established station procedures. The reactor trip was uncomplicated and the unit was subsequently restored to 100 percent reactor power on March 2, 2005.

4. Unit 1 Main Generator Field Ground Detection Alarm

On January 14, 2005, the licensee entered ERPIP 3.0, “ Immediate Actions”, for a severe weather and tornado watch. The inspectors were present in the control room when operators received a “Unit 1 Main Generator Field Ground” annunciator alarm. The inspectors assessed plant response and conditions specific to the event, and evaluated the performance of licensed operators. The licensee had unknowingly left a rollup door open allowing rainwater to enter the Turbine Building causing an accumulation of water on the 45' elevation close to the Unit 1 main exciter housing. The licensee determined that humidity and moisture from the rain water may have been drawn into the exciter housing by the fan system and that moisture was whisked across the ground detection board which caused a false alarm in the ground detection circuit. The inspectors observed control room activities and procedures, and reviewed operator logs to determine if operators performed the appropriate actions in accordance with their training and established station procedures.

5. Unit 2 Reactor Rapid Downpower

On March 18, 2005, control room operators reduced Unit 2 reactor power from 100 percent reactor power to 94 percent reactor power in accordance with OP-3, “Normal Power Operations,” following receipt of a high differential pressure alarm in the control room associated with the 22A/B traveling screens. Operators were dispatched to locally investigate the cause of the high differential pressure alarm. When the indicated differential pressure increased and met circulating water pump (CWP) trip criteria, operators appropriately secured the 22 CWP in accordance with OI-14A, “Circulating Water,” and commenced a rapid downpower due to limiting operating conditions caused by removing a second CWP from service (26 CWP was out-of-service for planned maintenance). Operators inspected the 22A/B traveling screens locally and determined that no significant debris existed on the traveling screens and the high differential pressure alarm did not indicate an actual condition. In response, the licensee terminated the rapid downpower at 94 percent reactor power and restarted 22 CWP. Further troubleshooting and evaluation by the licensee revealed that the differential pressure transmitter had failed and caused an erroneous output resulting in the false alarm. This failure was documented in the licensee’s corrective action program. The unit was restored to 100 percent reactor power on March 18, 2005.

The inspectors assessed plant response and conditions specific to the event, and evaluated the performance of licensed operators. The inspectors also reviewed control room procedures and operator logs to determine if operators performed the appropriate actions in accordance with their training and established station procedures.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15 - 7 samples)

a. Inspection Scope

The inspectors reviewed operability determinations to verify that the operability of systems important to safety was properly established, that the affected components or systems remained capable of performing their intended safety function. The inspectors reviewed the selected operability determinations to verify they were performed in accordance with NO-1-106, “Functional Evaluation - Operability Determination,” and QL-2-100, “Issue Reporting and Assessment.” The following operability evaluations were reviewed.

- 2A EDG failure of compression fitting in the jacket water system
- 21 AFW pump low oil level in turbine inboard bearing sightglass
- 1A EDG disconnected starting air line
- Impact of crosby relief valve test failures on Unit 1 and 2 saltwater system operability
- 2B EDG air start compressor found tripped
- Unit 2 reactor coolant system alloy 600 weld defects
- Potential degradation of fairbank morse EDG due to infrequent Unit 1 SRW pump alignment

b. Findings

Introduction. The inspectors identified a Non-Cited Violation (NCV) of very low safety significance (Green) for the failure to include in the Unit 1 OI-15 procedure instructions to place the normal service water pump in Pull-To-Lock (PTL) when the swing pump is running as specified in precaution L of OI-15. Operating procedures to ensure safety-related systems are maintained in a configuration such that design basis features are not challenged are required by Appendix “A” of Regulatory Guide 1.33, Revision 2, February 1978.

Description. During the Spring 2003 and 2004 unit outages, the licensee implemented modifications to the engineered safety features actuation system (ESFAS) sequencer, which affected both units. These modifications made it possible for two service water (SRW) pumps to simultaneously load onto a single bus being powered by an emergency diesel generator (EDG). Each unit has two in-service SRW pumps that are powered from separate electrical buses. Additionally, each unit has one swing pump that can be aligned to either bus. A SRW pump can either be running, not running with its hand switch in normal, or not running with its hand switch in the PTL position. Following the modifications, if the swing pump was running while the normally aligned pump was not running with its hand switch in normal, both pumps would attempt to load onto the same bus during a loss of offsite power (LOOP) event. This would not occur if the normal pump was in PTL because the pump could not start. Similarly, this would not happen if both the swing pump and the normal pump were running because the swing pump would load shed in this alignment. If the two SRW pumps had simultaneously loaded onto a single bus during a LOOP, concurrent with a loss of coolant accident (LOCA), the Fairbanks Morse EDG would be overloaded leading to an undervoltage condition on that bus. Three of the four safety-related EDGs are manufactured by Fairbanks Morse, while the fourth is manufactured by Societe Alsacienne de Constructions Mecaniques (SACM). The SACM EDG was not susceptible to this overloading because it is rated for higher loads. During the modification process, the licensee intended to add a precaution to the appropriate SRW system procedures to ensure that the normal pump's hand switch was in PTL if it was not running while the swing pump was running. This would prevent overloading events.

During the Spring 2003 Unit 2 outage, following completion of the sequencer modifications, the precaution was added correctly to the Unit 2, OI-15, "Service Water System," both in the precaution section and in the main body of the procedure. During the Spring 2004 Unit 1 outage; however, the precaution was only added to the Unit 1 OI-15 precaution section and certain sections in the main body. Additionally, when the procedure changes were made, the precaution was not added to all applicable surveillance test procedures.

On December 23, 2004, the licensee performed a SRW pump surveillance test and discovered during that test that the procedure did not refer to, or adhere to the precaution contained in OI-15. An issue report, IRE-002-167, was written to document this deficient condition. Subsequently, the surveillance test procedures for both Unit 1 and Unit 2 were corrected. On February 3, 2005, while reviewing IRE-002-167 to determine if the surveillance test procedures had been properly corrected, and to evaluate the extent of condition associated with this issue, the inspectors identified that the main body of the Unit 1 OI-15 procedure had not been appropriately revised and did not include the applicable precaution. Specifically, the procedures allowed for the normal pump to be off with its hand switch in the normal position while the swing pump was running. The inspectors promptly notified the licensee of the inadequate Unit 1 OI-15 procedure, and the potential for this condition to recur if the procedure section was utilized as written. The licensee documented the failure to include the service water precaution into their corrective action program as IRE-002-963.

The inspectors questioned the impact on past EDG operability in light of this potential overloading condition. As a result, the licensee performed an engineering evaluation of the Fairbanks Morse EDG with two SRW pumps loading simultaneously onto the bus. With the two SRW pumps loading onto the bus during a LOOP concurrent with a LOCA, the bus voltage would have dropped to 71.8% of the rated voltage. The inspectors reviewed the Licensee's UFSAR and Regulatory Guide 1.9, Rev. 3, "Selection, Design, Qualification, and Testing of Emergency Diesel Generator Units Used as Class 1E Onsite Electric Power Systems at Nuclear Power Plants," and determined that a drop in the bus voltage to 71.8% of the rated bus voltage is below the 75% acceptance criteria as stated in the EDG's design basis. The impact of the potentially degraded bus voltage on the EDG operation was not definitively established by the licensee. The inspectors concluded that the violation of the 75% bus voltage design criteria constituted a degradation of the EDG reliability.

Analysis. The inspectors determined that the licensee's failure to correct the OI-15 procedure to adhere to the Unit 1 OI-15 precaution L was a performance deficiency. Traditional enforcement does not apply for this finding because it did not have any actual safety consequences or potential for impacting the NRC's ability to perform its regulatory function nor was it the result of any willful violation of licensee or NRC requirements.

The finding is greater than minor since it was associated with the Mitigating System Cornerstone's human performance attribute and affected this cornerstone's objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e. core damage).

The inspectors determined that this finding was of very low safety significance (Green) using a Phase 1 risk assessment in accordance with the Significance Determination Process (SDP) for reactor inspection findings for at-power situations since the finding did not result in a design or qualification deficiency that was confirmed to result in a loss of function per Generic Letter 91-18 (Revision 1). The licensee determined the increase in core damage frequency (CDF) was less than 1E-7/yr.

The inspectors identified that a contributing cause of this finding was related to the cross-cutting area of human performance. The relevant causal factor was personnel because the Unit 1 service water procedures were not changed by operations department procedure writers although a procedure revision to this procedure was specified in the affected documents list.

Enforcement. Technical Specifications 5.4.1.a requires, in part, that written procedures shall be established, implemented, and maintained covering the applicable procedures recommended in Appendix "A" of Regulatory Guide 1.33, Revision 2, February 1978. Specifically, Regulatory Guide 1.33, Appendix "A", Section 3, Procedures for Startup, Operation, and Shutdown of Safety-Related PWR Systems, Part M, Service Water System. Contrary to this requirement, as of February 3, 2005, the licensee had not properly maintained approved station procedures and corrected the Unit 1 OI-15, Service Water System as was required because of modifications made to the ESFAS system during the 2004 Unit 1 Outage. These revisions were needed to preclude placing the service water pumps in an alignment that could affect the operability and reliability of the Fairbanks EDG. Because the failure is of a very low safety significance and has been entered into the corrective action program as IR3-002-963, this violation of TS 5.4.1.a is being treated as an NCV consistent with Section VI.A.1 on NRC Enforcement Policy: **NCV 05000317/200502-02, Failure to Change SRW Operating Procedure During Sequencer Modification.**

Enclosure

1R16 Operator Workarounds (71111.16A - 2 detailed samples)

a. Inspection Scope

The inspectors evaluated the effects of operator workarounds. This assessment evaluated the potential impact on the functionality of mitigating systems, as well as operator performance during postulated transient events in light of the identified workarounds. The inspectors performed an in-depth review of two specifically selected workarounds which are listed below. All workarounds were reviewed and assessed in light of the licensee's requirements for handling workarounds in accordance with Operations Administrative Policy (OAP) 2004-01, "Managing Operator Impacts." The workarounds were reviewed to determine: (1) if the functional capability of the system or human reliability in responding to an initiating event was affected; (2) the effect on the operator's ability to implement abnormal or emergency procedures; and (3) if operator workaround problems were captured in the licensee's corrective action program.

- 2-CVC-325 Inaccurate position indication due to faulty limit switch
- 12B RCP lower seal temperature sensor failure

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications (71111.17A - 1 sample)

a. Inspection Scope

The inspectors reviewed a permanent plant modification to verify the adequacy of the modification package, and to verify that the design and licensing bases requirements of the system were not degraded during the associated work activities. The inspectors also verified that post-modification testing was completed in accordance with established station procedures which adequately demonstrated continued reliability and satisfactory performance of the associated system. The inspectors interviewed cognizant licensee personnel and performed system walkdowns to verify the modification was implemented as planned.

- 21 AFW pump forced oil system installation

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing (71111.19 - 6 samples)

a. Inspection Scope

The inspectors observed and/or reviewed post-maintenance tests associated with the following work activities to verify that equipment was properly returned to service, and that appropriate testing was specified and conducted to ensure that the equipment was operable and could perform its intended safety function following the completion of maintenance. Post-maintenance testing activities were conducted as specified in station procedure MN-1-101, "Control Of Maintenance Activities." Post-maintenance test results associated with the maintenance activities listed below were reviewed.

- 23 HPSI breaker, motor, and controls inspection
- 22 component cooling water heat exchanger cleaning
- 22 containment spray pump MH and MJ switch replacements
- 21 containment air coolers following fan motor replacement
- 22 containment air coolers following fan motor replacement
- 2A EDG following jacket cooling water line replacement

b. Findings

No findings of significance were identified.

1R20 Refueling and Other Outage Activities (71111.20 - 1 sample)

a. Inspection Scope

The inspectors evaluated Unit 2 outage activities to ensure that the licensee considered risk in the development of outage schedules; the adherence to administrative risk reduction methodologies developed to control plant configuration; developed mitigation strategies for losses of key safety functions, and adhered to operating license and TS requirements that ensure defense in depth. The following specific areas were reviewed:

- Review of outage plan
- Monitoring of shutdown activities
- Licensee control of outage activities
- Reduced inventory and mid-loop conditions
- Refueling activities
- Monitoring of heatup and startup activities

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22 - 5 samples)

a. Inspection Scope

The inspectors observed and/or reviewed the surveillance tests listed below associated with selected risk-significant SSCs to verify that TS were properly complied with, and that test acceptance criteria was properly specified. The inspectors also verified that proper test conditions were established as specified in the procedures, no equipment preconditioning activities occurred, and that acceptance criteria had been satisfied. The following surveillance tests were reviewed:

- STP O-65N-2, 21 saltwater subsystem valve quarterly operability test
- STP O-5A-2, 21 AFW quarterly surveillance test
- STP O-8A-1, Test of 1A DG And 11 4KV bus LOCI sequencer
- STP O-66A-2, CVCS containment isolation valve operability test (Modes 5-6)
- STP O-66D-2, component cooling CNTMT isolation valve operability test (Modes 5-6)

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications (71111.23 - 4 samples)

a. Inspection Scope

The inspectors reviewed temporary modifications to determine whether system operability and availability were affected during and after the completion of the modifications. The inspectors verified that proper configuration control was maintained, appropriate operator briefings were planned, design modification packages were technically adequate, and post-installation testing was performed satisfactorily to ensure continued operability. The temporary plant modifications listed below were also reviewed against the licensee's criteria in MD-1-100, "Temporary Alterations."

- Temporary alteration No. 1-05-0003, jumpering out 12B RCP lower seal temperature failed element
- Temporary alteration No. 2-03-0019, alternate valve position indication for 2-RC-403-MOV, RCS PORV based upon torque switch in lieu of limit switch
- Defeating of a nuisance alarm associated with the 13kV (21 Bus) to 4kV (14 Bus) voltage regulator failed oil level instrument
- 11A reactor coolant pump CCW lo flow alarm disabled due to degraded flow switch with proper CCW flow

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

1EP4 Emergency Action Level (EAL) and Emergency Plan (E-Plan) Revision (IP 71114.04 - 1 Sample)

a. Inspection Scope

During the period of January 11 - March 31, 2005, the NRC has received and acknowledged the changes made to Calvert Cliff's E-Plan in accordance with 10 CFR 50.54(q), which Constellation Generation had determined resulted in no decrease in effectiveness to the Plan and which have concluded to continue to meet the requirements of 10 CFR 50.47(b) and Appendix E to 10 CFR 50. The inspector conducted a sampling review of the Plan changes which could potentially result in a decrease in effectiveness. This review does not constitute an approval of the changes and, as such, the changes are subject to future NRC inspection. The inspection was conducted in accordance with NRC Inspection Procedure 71114, Attachment 4, and the applicable requirements in 10 CFR 50.54(q) were used as reference criteria.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety (OS)

2OS1 Access Control to Radiologically Significant Areas (71121.01 - 14 samples)

a. Inspection Scope

The inspector reviewed radiological work activities and practices and procedural implementation during observations and tours of the facilities and inspected procedures, records, and other program documents to evaluate the effectiveness of Calvert Cliffs access controls to radiologically significant areas. This inspection activity represents the completion of fourteen (14) samples relative to this inspection area (i.e., inspection procedure sections 02.01, 02.02.a thru f, 02.03.d, 02.04.a thru c, 02.05.c, 02.06.a, and 02.07.a) in partial fulfillment of the annual inspection requirements.

Inspection Planning (02.01)

The inspector did not identify any licensee Performance Indicator (PI) events for the Occupational Exposure Cornerstone to review for follow-up during the inspection week of January 31, 2005.

Plant Walkdowns and RWP Reviews (02.02.a thru f)

During the inspection week of February 28, the inspector identified five exposure significant work areas within radiation areas (i.e., steam generator eddy current testing, reactor head inspections, pulling of in-core instrumentation (ICI) wires, reactor coolant pump replacement, and repair of alloy 600 indications). The inspector reviewed associated licensee controls and surveys of these areas to determine if controls (i.e., Special Work Permits (SWPs), work control instructions, surveys, postings, barricades, air sampling, engineering controls, and electronic personal dosimeter (EPD) alarm setpoints (both integrated dose and dose rate)) were acceptable. The inspector walked down selected areas or their perimeters with a survey instrument to verify the completeness and accuracy of surveys and postings. Several of these areas had the potential for becoming airborne radioactivity areas, and the inspector verified the performance of barrier integrity and engineering controls performance for those areas with the potential for individual worker internal exposures of greater than 50 millirems of Committed Effective Dose Equivalent (CEDE) (20 Derived Air Concentration (DAC)-hrs). The inspector did not review any internal dose assessments since there were no actual internal exposures greater than 50 millirems of CEDE.

During the inspection week of January 31, the inspector examined the licensee’s physical and programmatic controls for highly activated or contaminated materials (non-fuel) stored within the spent fuel pool. Physical controls included the fact that the spent fuel pool was surrounded by a foreign material exclusion (FME) barrier, and procedural controls for FME were in place. Additionally, there was a requirement, that a health physics representative be present when removing any material from the spent fuel pool, in several different health physics procedures (i.e., Radiation Safety Procedures (RSPs) 1-132 and 1-200). Also, there was a SWP for such activities (i.e., SWP 2005-0100).

Problem Identification and Resolution (02.03.d)

There were no PI events identified since the last inspection previous to the inspection week of January 31. The inspector did not identify any Technical Specification high radiation area (>1 rem per hour at 30 centimeters) occurrences or any very high radiation area (>500 rads in 1 hour at 1 meter) occurrences. Also, the inspector did not find indications of any unintended exposure occurrences equal to or exceeding the specified dose criteria.

Job-In-Progress Reviews (02.04.a thru c)

The work activities identified earlier (i.e., steam generator eddy current testing, reactor head inspections, pulling of in-core instrumentation wires, reactor coolant pump replacement, and repair of alloy 600 indications) included several which were estimated to result in the highest collective doses and which were active during the inspection week of February 28. On March 2, the inspector attended the integrated SWP job briefing for the second crew scheduled for ICI wire pulling. During tours of containment and during observations from the health physics remote monitoring station (including audio and visual surveillance, personnel teledosimetry, remote area radiation and air monitoring for remote job coverage), the inspector observed job performance and determined that radiological conditions in the work areas were being adequately communicated to workers through briefings, postings, and real-time verbal instructions. The inspector reviewed areas with significant dose rate gradients. The inspector noted that multiple dosimetry was used for entries under the reactor head.

High Risk Significant, High Dose Rate HRA and VHRA Controls (02.05.c)

The inspector verified adequate posting and locking of all reasonably accessible entrances to high-dose-rate high radiation areas (HRAs) and very high radiation areas (VHRAs) during the inspection week of January 31. The inspector accomplished this during tours of the main Radiologically-Controlled Area (RCA) on several different occasions during this inspection week. The inspector used the Area Status Report Cover Sheet and Area Status Reports from Procedure RSP 1-104 for the period of January 3 to January 9, 2005.

Radiation Worker Performance (02.06.a)

During job performance observations during the inspection week of February 28, the inspector observed radiation worker performance with respect to stated radiation protection work requirements. The inspector determined that they were aware of the significant radiological conditions in their workplace and of the SWP controls/limits in place and that their performance took into consideration the level of radiological hazards present.

Radiation Protection Technician Proficiency (02.07.a)

During job performance observations during the inspection week of February 28, the inspector observed radiation protection technician performance with respect to all radiation protection work requirements. The inspector determined that they were aware of the radiological conditions in their workplace and of the SWP controls/limits and that their performance was consistent with their training and qualifications with respect to the radiological hazards and work activities.

Related Activities

During the inspection on February 1, 3, and 4, the inspector observed RCA entries and exits being made by radiation workers at the primary RCA access control point to verify compliance with requirements for RCA entry and exit, wearing of record dosimetry, and issuance and use of alarming electronic radiation dosimeters. The inspector toured various elevations in the auxiliary building to verify the adequacy of the radiological controls which were being implemented. The inspector reviewed observed work activities for compliance with the SWP requirements. During these observations and tours the inspector reviewed, for regulatory compliance, the posting, labeling, barricading, and level of radiological access control for locked high radiation areas (LHRAs), HRAs, radiation and contamination areas, and radioactive material areas. On February 1 through 4, the inspector observed the morning turnover meetings for the HP technicians.

The inspector performed a selective examination of documents (as listed in the List of Documents Reviewed section) to evaluate the adequacy of radiological controls.

The review in this area was against criteria contained in 10 CFR 19.12, 10 CFR 20 (Subparts D, F, G, H, I, and J), Technical Specifications, and procedures.

b. <u>Findings</u>

No findings of significance were identified.

2OS2 <u>ALARA Planning and Controls</u> (71121.02 - 6 samples)

a. <u>Inspection Scope</u>

The inspector reviewed the effectiveness of the licensee’s program to maintain occupational radiation exposure as low as is reasonably achievable (ALARA). This inspection activity represents the completion of six (6) samples relative to this inspection area (i.e., inspection procedure sections 02.02.e*, 02.03.c*, 02.04.a.1, 02.05.b* and c*, and 02.06) in partial fulfillment of the biennial inspection requirements.

<u>Radiological Work Planning (02.02.e*)</u>

During the inspection week of January 31, 2005, the inspector reviewed the integration of ALARA requirements into work procedures and SWP documents. This review indicated the following. Procedure OM-1, “Outage Management Program,” requires the individual craft organizations to develop radiation dose estimates for their work activities on an agreed-upon schedule with milestones and to complete their outage work activities within the estimated radiation dose. Procedure OM-1-100, “Refueling Outage Management,” describes, in part, the required process for planning and scheduling refueling outages, including the milestones for completion of SWPs and radiation dose estimates. This procedure also describes High Impact Teams (HITs) which are multi-disciplined and are responsible for the planning and scheduling of specific refueling outage evolutions, including the development of radiation dose estimates and of ways to improve the previous ALARA performance. The site ALARA group provides the historical ALARA data to these teams. Procedure OM-09, “High Impact Team (HIT) Guideline” provides guidance, which includes guidance on performing dose reduction research, on a milestone for completion of a HIT ALARA plan, and on a milestone for presentation of the HIT ALARA plan to the Site ALARA Committee. Procedure NO-1-117, “Integrated Risk Management,” describes how SWPs are categorized as low, medium, or high risk based on an overall risk assessment, including radiation safety. Procedures RP 1-101, “ALARA,” and RSP 1-200, “ALARA Planning and SWP Preparation” describe how the ALARA requirements are incorporated into the SWP documentation.

<u>Verification of Dose Estimates and Exposure Tracking Systems (02.03.c*)</u>

During the inspection during the week of February 28, 2005, the inspector reviewed the licensee’s exposure tracking system. The inspector determined that the level of exposure tracking detail, exposure report timeliness, and exposure report availability distribution were sufficient to support control of collective exposures. There were numerous SWPs, and most SWPs addressed one or more different and separate work activities. For the conduct of exposure significant maintenance work, the inspector noted evidence that licensee management was aware of the exposure status of the work and intervened when exposure trends increased beyond exposure estimates.

Job Site Inspections and ALARA Control (02.04.a.1)

The work activities identified earlier (i.e., steam generator eddy current testing, reactor head inspections, pulling of in-core instrumentation wires, reactor coolant pump replacement, and repair of alloy 600 indications) included several which presented the greatest radiological risk to workers and which were active during the inspection week of February 28, 2005. The inspector evaluated the licensee's use of ALARA controls for these work activities by evaluating the licensee's use of engineering controls to achieve dose reductions. The inspector found that procedures and controls were consistent with the licensee's ALARA reviews, that the dose reduction benefits afforded by the shielding were evaluated, and that sufficient shielding of radiation sources was provided.

Source-Term Reduction and Control (02.05.b* and c*)

During the inspection week of January 31, 2005, the inspector determined that the licensee had developed an understanding of the plant source-term, including knowledge of input mechanisms to reduce the source term. This understanding was evidenced in their five-year ALARA plan. This plan included permanent shielding and permanent scaffolding in containment, the same in the auxiliary building, engineering modifications and changes in equipment lineups to reduce dose, changes to test methods, zinc injection, and reactor head replacement. The radiation protection group also worked closely with the chemistry group to assure that the shut down chemistry procedure provided for an appropriate clean-up of the reactor coolant during shutdown.

Based on the previous paragraph, the inspector assessed that the licensee had a source-term control strategy in place. Upon review of the five-year ALARA plan, the inspector concluded that specific sources had been identified by the licensee for exposure reduction actions and that priorities had been established by the licensee for implementation of these actions. The licensee indicated that permanent shielding had been installed in Unit 1's containment during the 2004 refueling outage and that permanent shielding was scheduled to be installed in Unit 2's containment during the upcoming 2005 refueling outage. Also, the ALARA plan showed that a dose-saving engineering modification would be implemented for Unit 2's upcoming 2005 refueling outage.

Radiation Worker Performance (02.06).

During the inspection week of February 28, 2005, the inspector observed radiation worker and RP technician performance during work activities being performed in radiation areas, airborne radioactivity areas, or high radiation areas. The inspector concentrated on work activities that presented the greatest radiological risk to workers which were identified earlier in this section of the report. The inspector determined that workers demonstrated the ALARA philosophy in practice (e.g., workers were familiar with the work activity scope and tools to be used and were utilizing ALARA low dose waiting areas). The inspector found that work activity controls were being complied within almost all instances. The inspector observed radiation worker performance and determined that the training/skill level was sufficient with respect to the radiological hazards and the work involved.

Related Activities

On January 31, 2005, the inspector observed a training session for site supervision. The training session was titled as ALARA Is For Everyone. The inspector discussed preparations for the upcoming 2005 refueling outage for Unit 2 with the Radiological Engineering Supervisor and the Acting Radiation Protection Manager. The inspector reviewed the projected outage dose estimates (as of January 31, 2005) for the various outage activities and SWPs. Also, the inspector examined the reports by six ALARA high-impact teams (i.e., reactor path optimization, reactor coolant pumps, reactor head inspection, alloy 600/in-service inspection/nondestructive examination work, scaffolding work, and balance of plant). The inspector reviewed eleven SWP/ALARA packages for the upcoming outage work. The inspector reviewed the ALARA and Chemistry Scripts for the 2005 Unit 2 refueling outage and discussed the shutdown chemistry sequence to be used with a cognizant plant chemist.

The inspector performed a selective examination of documents (as listed in the List of Documents Reviewed section) for regulatory compliance and for adequacy of control of radiation exposure.

The review was against criteria contained in 10 CFR 20.1101 (Radiation protection programs), 10 CFR 20.1701 (Use of process or other engineering controls), and procedures.

b. Findings

No findings of significance were identified.

2OS3 Radiation Monitoring Instrumentation and Protective Equipment (71121.03 - 3 samples)

a. Inspection Scope

The inspector reviewed the program for health physics instrumentation and protective equipment to determine the accuracy and operability of the instrumentation and equipment. This inspection activity represents the completion of three (3) samples relative to this inspection area (i.e., inspection procedure section 02.04.a and c and 02.05) in partial fulfillment of the biennial inspection requirements.

Problem Identification and Resolution (02.04.a and c).

During the inspection week of February 28, the inspector reviewed the licensee's experience with personnel internal exposures. This item is covered in Section 2OS1 of this report as Item 02.02.e.

During the inspection week of January 31, the inspector reviewed issues identified in the Corrective Action Program (CAP) since the last inspection. The inspector did not identify any significant repetitive deficiencies or significant individual deficiencies during this examination. The CAP did identify several minor deficiencies regarding radiation monitoring instrumentation, and these were captured for trending purposes. There was no self-assessment in this area since the last inspection.

Radiation Protection Technician Instrument Use (02.05)

During the inspection week of February 28, the inspector examined the radiation detection instruments staged for use to verify the calibration expiration and source response check currency. The inspector also made observations at the issue point for the radiation detection instruments staged for use to check radiation protection technicians for appropriate instrument selection and self-verification of instruments operability prior to use.

The review was against criteria contained in 10 CFR 20.1501, 10 CFR 20 Subpart H, Technical Specifications, and procedures.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA2 Identification and Resolution of Problems

1. Corrective Action Review by Resident Inspectors

a. Inspection Scope

Continuous Review

The inspectors performed a daily screening of items entered into the licensee's corrective action program as required by Inspection Procedure 71152, "Identification and Resolution of Problems." The review facilitated the identification of potentially repetitive equipment failures or specific human performance issues for follow-up inspection. It was accomplished by reviewing each issue report and attending daily screening meetings, and accessing the licensee's computerized database.

b. Findings

No findings of significance were identified.

2. Identification and Resolution of Problems - Inservice Inspection

a. Inspection Scope

The inspector reviewed a sample of issue reports that identified problems associated with inservice inspection. The inspector verified that the problems were accurately recorded in the issue reports and that the corrective action taken was appropriate.

b. Findings

No findings of significance were identified.

3. Identification and Resolution of Problems - Occupational Radiation Safety

a. Inspection Scope

During the week of January 31, the inspector selected ten issues identified in the CAP for detailed review (i.e., Issue Report (IR) Nos. IRE-001-949, -001-992, -002-147, -002-241, -002-242, -002-307, -002-374, -002-405, -002-406, and -002-466). The issues were associated with a trend of personnel contamination events, possible area cross-contamination, lack of documentation controls, instrumentation found out-of-tolerance, instrumentation out-of-service due to erratic alarms, conflicting room postings, incomplete data entries, the required expansion of a contamination boundary, an increased number of contamination incidents, and missing survey information, respectively. During the week of February 28, the inspector selected seven issues identified in the CAP for detailed review (i.e., IR Nos. IRE-002-993 and IRE-003-291, -421, -436, -453, -462, and -564. The issues were associated with an evaluation of Unit 2's source term, a problem with the SWP transfer process, signing in on an incorrect SWP, an electronic dosimeter dose alarm, the requirements for removing protective clothing, briefings for entry into noble gas environments, and issues with use of lapel air samplers, respectively. The documented reports for the issues were reviewed to determine whether the full extent of the issues was identified, an appropriate evaluation was performed, and appropriate corrective actions were specified and prioritized.

b. Findings

No findings of significance were identified.

4OA3 Event Followup (71153 - 1 sample)

a. Unit 1 Reactor Trip

On March 1, 2005, the Unit 1 reactor was manually tripped from 15 percent reactor power. The inspectors were present in the control room monitoring control room operations associated with a scheduled reduction in reactor power to perform piping repairs when the reactor trip occurred. The inspectors assessed plant response and conditions specific to the event, evaluated the performance of licensed operators, and documented the details of this event in 1R14. As part of the event follow up, the inspectors reviewed and assessed critical plant parameters from chart recorders, sequence of event recorder logs, and compared operator performance to required station procedural requirements. The reactor trip was uncomplicated, and the unit was restored to 100 percent reactor power on March 2, 2005.

b. Findings

No findings of significance were identified.

4OA4 Cross Cutting Aspects of Findings

Cross-References to Human Performance Findings Documented Elsewhere

Section 1R04 describes a finding in which the licensee inadvertently drained the RCS because physical boundaries which were established in a tagout to support reactor coolant pump maintenance were inadequate. (Section 1R04)

Section 1R15 describes a finding in which licensee resources failed to make required corrections to a Unit 1 Service Water System procedure. (Section 1R15)

4OA5 Other

1. Temporary Instruction (TI) 2515/150, Revision 3 - Reactor Pressure Vessel Head And Vessel Head Penetration Nozzles (NRC Order EA-03-009)

a. Inspection Scope

The inspection assessed the effectiveness of the licensee's reactor pressure vessel (RPV) and vessel head penetration (VHP) nozzle inspection in detecting small amounts of boric acid, primary water stress corrosion cracking (PWSCC) in VHP nozzles, and boric acid flow through the interference zone of the fit of the VHP nozzles. The inspection consisted of interviews with ultrasonic and visual examination personnel, data analysts, and engineering personnel. The UT and VT analysts' training and qualification records were reviewed to verify the licensee's personnel qualification process adequately prepared the assigned staff to perform the examination and analyze accumulated ultrasonic data. Also, the inspector reviewed the examination procedures to determine the adequacy of the guidance and examination criteria to implement the examination plan.

For the bare metal visual examination, the inspector reviewed accuracy of the licensee's RPV head's susceptibility calculation and performed a visual observation of the RPV head to look for small boron deposits. The inspector observed the illumination check and resolution test with the appropriate test chart characters for the remote camera in order to verify that small boric acid deposits could be detected. Portions of the examination were observed to verify that the approved procedures were being followed. Inspection photographs of eight control element drive mechanisms (CEDMs), one in-core instrumentation (ICI) nozzle, and the vent line were reviewed for evidence of boron. The inspector verified that appropriate corrective action was taken for indications identified during the examination process.

For the ultrasonic examination of the RPV penetrations, the inspector witnessed the calibration of the ultrasonic equipment to verify that any indications identified would be accurately characterized. Portions of the examination were observed to verify that the approved procedures were being followed. Ultrasonic records of 12 CEDM nozzles, one in-core instrumentation penetration, and the vent line were reviewed to verify that there were no cracks in the nozzle or J-groove weld, and that no boron had leaked into the interference zone fit of the CEDM nozzle. The inspector verified that indications identified during the examination process were evaluated and appropriate corrective action was taken.

The specific reporting requirements of TI 2515/150, Revision 3 are documented in Attachment 1.

b. Findings

No findings of significance were identified.

2. Temporary Instruction 2515/160 - Pressurizer Penetrations and Steam Space Piping Connections in U.S. Pressurized Water Reactors (NRC Bulletin 2004-01)

a. Inspection Scope

The inspection assessed the licensee's pressurizer penetration and steam space piping connection inspections effectiveness in detecting small amounts of boric acid. The inspection included interviews with ultrasonic and visual examination personnel and engineering personnel to assess their knowledge of these activities. The examination personnel's training and qualification records were reviewed to verify the licensee's personnel qualification process adequately prepared the assigned staff to perform the examination and analyze the results. The inspector reviewed the examination procedures to determine whether they provide adequate guidance and examination criteria to implement the examination plan. Ultrasonic and visual examination reports were reviewed for items requiring corrective action.

The inspector performed a visual observation of six pressurizer instrument penetrations and several pressurizer heater penetrations to look for small boron deposits. The inspector observed the calibration of the ultrasonic equipment. Portions of the VT and UT examination the RV 200 pressurizer relief valve and the pressurizer heater penetrations VT examination were observed to verify that the approved procedures were being followed.

The specific reporting requirements of TI 2515/160 are documented in Attachment 2.

b. Findings

No findings of significance were identified.

3. Temporary Instruction (TI) 2515/153, Revision 1 - Reactor Containment Sump Blockage (NRC Bulletin 2003-01)

a. Inspection Scope

The inspectors reviewed the sump blockage compensatory measures that the licensee proposed in response to the NRC Bulletin 2003-01,"Potential Impact of Debris Blockage on Emergency Sump Recirculation at Pressurized-Water Reactors," dated June 9, 2003. The inspectors utilized TI 2515/153, Revision 1, to examine these compensatory measures. In addition, the inspectors reviewed plant procedures, Unit 1 containment walkdown documentation, the licensee's written response to the NRC Bulletin 2003-01, and the licensee's response to the NRC request for additional information dealing with the 2003-01 Bulletin.

The licensee's correspondence regarding the NRC Bulletin 2003-01 described interim compensatory measures that would be implemented to reduce the risk associated with degraded emergency core cooling systems and containment spray system recirculation functions. The inspectors reviewed the licensee's compensatory measures program to determine if all the measures stated in the licensee's responses regarding the 2003-01 Bulletin were included. The licensee's compensatory measures included revision of plant procedures followed by training courses for instruction on these procedural changes. The inspectors interviewed the plant's procedure technical staff and examined the modified procedures to confirm that the procedural changes had been either finished, or would be finished by the agreed upon date. The inspectors interviewed operators and training staff personnel to confirm that the associated training had been taught or appropriately scheduled.

Other than the compensatory measures, the licensee quantified potential debris sources by conducting a Unit 1 containment walkdown. There are no plans to conduct a Unit 2 debris source quantification because the licensee determined that these sources would be comparable to those identified in Unit 1. The Unit 1 walkdown analyzed debris sources which included insulation, coating, and foreign material. The walkdown also examined various flowpaths to the sump to identify locations for which flowpaths could become clogged. The physical condition of both the Unit 1 and Unit 2 sumps were examined by the inspectors to assess whether gaps or the existence of other degraded conditions existed. At this time there are no advance preparations to expedite the performance of sump-related modifications. The inspectors reviewed the licensee's debris source quantification by examining the debris source report. The inspectors also conducted a walkdown of containment to examine insulation, coatings, foreign materials, and actual sump condition.

b. Findings

No findings of significance were identified.

4. World Association Of Nuclear Operators (WANO) Peer Report Review

a. Inspection Scope

On March 28, 2005, the Senior Resident Inspector reviewed a preliminary WANO report, dated January 11, 2005, that discussed the results of a peer review that was performed at Calvert Cliffs during November, 2004.

b. Findings

No findings of significance were identified.

40A6 Meetings, Including Exit

On April 14, 2005, the inspectors presented the inspection results to Mr. Dave Holm, and other members of his staff. The licensee had no objections to the NRC's observations. The inspectors confirmed that proprietary information was not provided or examined during the inspection.

4OA7 Licensee-Identified Violations

The following violation of very low safety significance (Green) was identified by the licensee and is a violation of NRC requirements. In accordance with the NRC Enforcement Policy, the violation is listed below:

TS 5.4.1.a and RG 1.33 (Rev. 2, Appendix A, February 1978, Item7.e(1)) require that written procedures shall be implemented covering access control to radiation areas including a radiation work permit system. Calvert Cliffs Procedure RSP 1-104, Rev. 18, Area Posting and Barricading, requires that each high radiation area (HRA) shall be controlled by a Special Work Permit (SWP) and that any individual shall be made aware of the dose rate levels in the area prior to being permitted to enter. Contrary to this, on March 1, 2005, a radiation worker entered a high radiation area while on a non-HRA SWP without having been briefed on the dose rate levels in the area. This was documented in the licensee's corrective action program as Issue Report No. IRE-003-818. This finding is of very low safety significance because it did not result in an overexposure, did not create a substantial potential for overexposure, and did not compromise the licensee's ability to assess dose to workers.

ATTACHMENTS:

ATTACHMENT 1

TI 2515/150, Revision 3 - REACTOR PRESSURE VESSEL HEAD AND VESSEL HEAD PENETRATION NOZZLES (NRC Order EA-03-009)

Reporting Requirements

a.1. The Visual examination was performed by qualified and knowledgeable personnel with certification to the American Society of Mechanical Engineers (ASME), Section XI, Level II and Level III for visual examiners. In addition, Level II and Level III examiners had received training in this type of inspection. The training included a review of industry experiences, lessons learned, inspection results and procedure requirements.

Ultrasonic test personnel performing calibration or data analysis functions were qualified to a minimum of Level II in ultrasonic examination. In addition, data analysis personnel had training in the analysis system, reactor head penetration (RHP) examination techniques and RHP analysis methods.

a.2. Both the UT and VT examinations were performed using adequate procedures. The procedures had been demonstrated on a mock-up of a reactor vessel head. The procedures specified the extent of the inspection required, provided documentation requirements and provided clear inspection standards and acceptance criteria on which personnel were trained. The examination procedure was approved by the licensee's Level III ultrasonic test examiner.

a.3. The examinations were adequate to identify, resolve, and disposition deficiencies.

a.4. The examinations performed were capable of identifying the primary water stress corrosion phenomena described in Order EA-03-009.

b. The reactor vessel head was free of dirt, debris, insulation, significant oxidation and any material that could adversely affect viewing of the penetrations (360 degrees around the circumference of the nozzle) and the vessel head in its entirety. The nozzle penetrations, including the vent line, were remotely inspected for a full 360 degree view using a high resolution camera delivered by a robotic crawler.

c. Small boron deposits could be identified and characterized by the visual technique used. No boron deposits were identified at the penetrations or on adjacent areas of the vessel head.

d. A minor, single indication in each of the toes of nine J-groove welds was identified by the ultrasonic examination. Three of these were characterized as rounded indications by PT. These indications were removed by grinding. The second PTs of the welds were free of indications. Each of these indications were present during the 2003 inspection.

e. There were no significant items which would impede an effective visual examination of the outside surface of the head and penetrations in the future.

For the ultrasonic examination of the CEDM nozzles, nozzle distortion prevented the axial probe from obtaining complete scan of the nozzles examined in the area below the J-groove weld. The circumferential probe maintained better contact and was able to obtain a complete scan in the area below the J-groove welds except the bottom ½" of the nozzle. At approximately ½" above the bottom of the nozzle, the bottom transducer cannot receive the signal from the upper transducer.

f. The basis for the temperature used (593.7E F) in the susceptibility ranking calculation was an analysis documented in Combustion Engineering report CE NPSD-1074, CEOG task 953 (Evaluation of Reduction in Fluid Temperature in the Reactor Vessel Upper Plenum Due to Increased Bypass Flow, dated February 1997). The temperature in the upper head region was determined using a model with analysis performed that is typical for Calvert Cliffs, Unit 2 (2700 MWt). There have been no changes in plant operation to date that have resulted in a change in the original maximum design temperatures in the upper head region.

g. No indications were found during the UT examination that required the use of the flaw evaluation guidelines in Appendix D.

h. If a boric acid leak was identified, the RPV head visual inspection procedure required that the camera on the robotic crawler scan the portion of the CEDM above the head to determine if the source of the leak was above the RPV head.

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

ATTACHMENT 2

TI 2515/160, - PRESSURIZER PENETRATION NOZZLES AND STEAM SPACE PIPING CONNECTIONS IN U.S. PRESSURIZED WATER REACTORS (NRC BULLETIN 2004-01)
Reporting Requirements

a.5. The Visual examination was performed by qualified and knowledgeable personnel with certification to the American Society of Mechanical Engineers (ASME), Section XI, Level II and Level III for visual examiners. In addition, Level II and Level III examiners had received training in this type of inspection. The training included a review of industry experiences, lessons learned, inspection results and procedure requirements.

Ultrasonic test personnel were qualified to a minimum of Level II in ultrasonic examination and demonstrated their procedure on an appropriate mock-up prior to performing each inspection.

a.2. The examination methods were performed in accordance with demonstrated procedures. The ultrasonic procedure had been demonstrated on mock-ups of each steam space piping connection. The personnel performing the visual inspection received training to identify boric acid deposits. The procedures specified the extent of the inspection and provided detailed documentation requirements.

a.3. The visual and ultrasonic methods used were able to identify, disposition, and resolve deficiencies.

a.4. The visual inspection was capable of identifying the leakage in pressurizer penetration nozzle or steam space piping components as discussed in NRC Bulletin 2004-01.

b. The pressurizer upper head and steam space piping connections were free of dirt, debris, insulation, significant oxidation, or any other material that could adversely affect the viewing of the penetrations and connections. The pressurizer lower head was free of dirt, debris, and significant oxidation. Insulation on the lower head was lowered in sections to allow viewing of a portion of heaters and then replaced before the next section of insulation was removed. The two instrument nozzles on the bottom head and the instrument nozzle on the lower shell have mechanical nozzle seal assemblies (MNSA) installed.

c. The visual inspection performed was the direct visual type.

d. The examination personnel were able to conduct a full 360 inspection of all penetrations and steam space connections.

e. Small boron deposits could be identified and characterized by the visual techniques used. No boron deposits were noted.

f. No material deficiencies were identified that required repair. However, MNSAs were installed on three of the four top head instrument nozzles as a preventive measure.

g. Lowering a section of the insulation on the pressurizer lower head just enough to allow heater penetration and instrument nozzle inspection made the inspection more difficult than full insulation removal, but still allowed a complete inspection.

h. Ultrasonic examination was performed on the three steam space connections (pressurizer spray line, RV 200 and RV 201 relief valve lines). No indications were detected.

I. There were no indications of boric acid leaks from the inspections performed.

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel:

D. Austin, Areva Reactor Head Visual Inspection Project Manager
J. Ball, Health Physics Work Leader (Operations)
T. Beck, Reactor Vessel Visual Inspection QDA for Constellation
J. Beverly, Health Physics Technician
J. Blankenship, Health Physics Work Leader (Radiological Engineering)
C. Brevig, Health Physics Technician
C.J. Conner, Steam Generator Eddy Current QDA for Constellation
M. Cox, Reactor Head Inspection Project Manager
L. Daniels, Project Manager Weld Overlay Repairs
E. Deogracias, Health Physics Work Leader (Operations)
J. De Sando, Senior Engineer
M. Dobson, Areva Level III Steam Generator Eddy Current Analyst
E. Eshelman, Senior Chemist
S. Etnoyer, Plant Health Physicist
H. Evans, Health Physics Work Leader (Dosimetry)
P. Furio, Regulatory Matters Supervisor
M. Geckle, Manager, Nuclear Operations
G. Gwiazdowski, Director, Nuclear Security
M. Hacker, Areva Level III Reactor Head UT Analyst
K. Hoffman, Dissimilar Metal Inspection Nightshift Supervisor
D. Holm, Acting Plant General Manager
M. Hunter, Auxiliary Feedwater System Manager
J. Johnson, Engineering Analyst
V. Johnson, Health Physics Technician
P. Jones, Senior Plant Health Physicist
G. Khouri, Engineer for Reactor Vessel Head Inspection
T. Kirkham, Health Physics Supervisor (Operations)
E. Kreahling, System Engineer
L. Larragoite, Director of Licensing
J. Lenhart, Health Physics Work Leader (Operations)
T. Lupold, Project Manager Dissimilar Weld Inspection Program
J. Mate, Steam Generator Eddy Current Project Manager
K. Mills, Operations General Supervisor
K. Neitmann, Plant General Manager
R. Pace, Shift Manager
J. Robinson, Fire Protection Engineer
S. Sanders, General Supervisor of Health Physics
M. Stanley, Safety Specialist
D. Svendsgaard, Health Physics Technician
D. Taylor, Health Physics Technician

G. Vanderheyden, Site Vice President
J. York, Health Physics Supervisor (Support)
M. Yox, Senior Emergency Analysis

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened

None

Closed

None

Opened and Closed

05000318/2005002-01	NCV	Failure To Establish Adequate Clearance Order Boundaries (Section 1R04)
05000317/2005002-02	NCV	Failure to Change SRW Operating Procedure During Sequencer Modification (Section 1R15)

LIST OF DOCUMENTS REVIEWED

Section 1R01: Adverse Weather Protection

EP-1-108 Severe Weather Preparation Revision 0
ERPIP 3.0 Attachment 20 Severe Weather
OI-22K Turbine Building Ventilation Revision 2
Unit 1 Reactor Operators Log
IRE-002-500 Received annunciator A-54 Main Generator Field Ground Alarm
MO#1200500064 - Generator Field Ground Detection Annunciator
DWG 61077ASH399 - Block Diagram CST No. 12 Level Instrument Loops L5610 and L5611

Section 1R04: Equipment Alignment

Unit 1 Service Water System Complete System Alignment

OI-15 Attachment 1, Service Water Valve Alignment
OI-15 Attachment 2, Service Water Instrument Valve Alignment
IR4-030-026, Service Water to Turbine Building Isolation CV did not stroke in less than or equal to 35 seconds as Required by STP-O-56A-1
IR4-034-232, Two ETP's Scheduled for same day created an unsatisfactory potential system alignment.
IRE-002-167, STP O-73B Has a sequence of steps that violates a general precaution of OI-15
IRE-003-231, The Service water flow control valves to the Fairbanks Morse EDG cause a minor water hammer on valve opening & closing.

IR4-033-542, During the post maintenance test of 11B Service water heat exchanger, 11A SRW heat exchanger would not pass the required amount of flow.
IR4-023-550, Service water heat exchangers continue to have trouble with fowling.
IRE-002-963, Section 6.3 of OI-15-1does not adhere to Precaution 5.0L
AIT ER200400025, Due to frequent cleaning, the service water heat exchanger plate tabs and elastomers are degrading.
MO 1200403985, There is a Service Water leak of approximately 1 drop/5 minutes at the threaded inlet of manual valve 1HV-SRW-517.
MO 1200303236, Clean Plenum and Strainer 11A SRW Hx.
MO 1200500870, 1-SRW-1625-RV is leaking by.
Maintenance Rule Scoping Document, Service water system.
Maintenance Rule Indicators, Service water 2004 4th Quarter indicators.
Maintenance Rule Identified events, Service water system Performance Criteria information
Maintenance Rule Functional Failures and Leakrate Data, Service water system data
Plant Drawing 60706SH0001, Service Water Cooling - Turbine Area
Plant Drawing 60706SH0002, Service Water Cooling System - Auxiliary Building & Containment

Unit 1 SRW Pump Alignment

IRE-002-167, STP O-73B has a sequence of steps that violated a general precaution of OI-15
IRE-002-963, Section 6.3.C of OI-15-1 violates OI-15 general precaution
OI-15-1, Service Water System - Unit 1
OI-15-2, Service Water System - Unit 2
STP O-73B-1, Service Water Pump Quarterly Test - Unit 1
STP O-73B-2, Service Water Pump Quarterly Test - Unit 2
Loading Test Page, 2ZB Loading Sequence Voltage Profile - As Sequenced
Daily Event log, Utilized OI-15 6.3.C to shift 13 SRW Pp from 11 4Kv bus to 12 Header and 14 4Kv bus
Basis B0857, Basis providing an explanation on the proper operation of the swing SRW pumps.
ES199700364, Action item for reviewing and correcting any procedure changes to uphold Basis B0857
Calvert Cliffs UFSAR, Chapter 8, Electrical Systems, Section 8.4.1 Fairbanks Morse Emergency Diesel Generators
Regulatory Guide 1.9, Revision 3, Selection, Design, Qualification, and Testing of Emergency Diesel Generators Units Used as Class 1E Onsite Electrical Power Systems at Nuclear Power Plants
NS-2-101 POSRC/PRC Presentation Form, Information Packet discussing instance where EDG was overloaded in 1995

BAST/BA Relief Valves System Walkdown

OI-2A, Chemical and Volume Control System Operating Instructions
Diagram 60730 SH 0001, Chemical and Volume Control System Diagram

21A RCP Maintenance Tagout Alignment

Control room log on 03/08/2005 at 01:25, Isolation could not be obtained for working 2RC-139 & 140, as the penetration was below the current reduced inventory level (approx. 38').

Control room log on 03/08/2005 01:32, narrative of events surrounding the discovery of a slowly lowering RCS level that resulted in a loss of ½ inch RCS level by GEMS.
IRE-003-997, RCS level was too high to support replacement of 2-RC-139 and 140 under MO 2200302013.
Prompt Investigation, Prompt Investigation information package for IRE-003-997
Email from Tim Riti, Correction of IR which stated incorrect level decrease.
MO# 2200302013, Replace Valves 2HVRC-140/139 Assemblies
OP-7, Shutdown Operation
AOP-3B, Abnormal Shutdown Cooling Conditions
MN-1-101, Control of Maintenance Activities
NO-1-112, Safety Tagging
Clearance 2200400253, Clearance order on the work for the RCP drain valves
Clearance Stub 2200302013-A1, Clearance Stub authorizing work on the drain valves, and presenting a RCS Level boundary of < 38' 6"
Dwgs. FSK-MP-3199, Differential Pressure Indicators on RC Pump #21A
FSK-MP-1312, Typical Arraignment for Differential Pressure Indicators on RC Pumps 11A, 11B, 12A, & 12B
62170SH0003, Component Cooling System
62729SH0001, Reactor Coolant System

Unit 2 Component Cooling (CC) Water System Alignment While Cleaning 22 CC Heat Exchanger

MO#: Clean 22 Component cooling water heat exchanger
Clearance ID#: 2200400728, Tagout for cleaning the 22 CCHX
Drawing: OM-450SH0002, Component Cooling Water
OI-29, Saltwater System
NO-1-203, Operations Performance Evaluation Requirements

2A EDG During And Following The Repair Of A Jacket Cooling Water Leak

IRE-002-742 - The 2A DG has developed a jacket cooling water leak at a compression fitting
IRE-002-768 - The 2A EDG scavenging air blower cover on the east end of the engine was leaking oil during the run today
Clearance Order 2200500162 - Remove the 2A DG from service and repair the leak
Dwg. No. 60727SH0001 - Diesel generator cooling water, starting air, fuel, and lube oil
2A DG Operator Logs for ½6/2005
STP O-8A-2 Test of 2A DG and 4 KV Bus 21 LOCI Sequencer Rev 24

Unit 2 4 KV Alternate Feeder Alignment To Prevent A Dual Unit Trip In The Event Of A Loss Of Transformer P-13000-1

OI-27C, 4.16 KV System

21 AFW Train During 21 AFW Pump Testing

STP O-5A-2, Auxiliary feedwater system quarterly surveillance test
Diagram 62583, Auxiliary Feedwater System

Section 1R05: Fire Protection

1A EDG Fire System Zone #1 Failed To Pressurize Due To Stuck Closed Check Valve

IRE-001-963, Unable to Complete STP M-491-1A-1 because Zone #1 header failed to pressurize.
STP M-491-1A-1, Functional Test of 1A Diesel Generator Fire Protection and Detection Systems.
MO# 0200302527, 1A DG Fire System Air compressor is pressing up pressure to 36oz. which is greater than normal.

Unit 1 and Unit 2 West Penetration Rooms

SA-1-101- Fire Fighting
Fire Fighting Strategies Manual

Section 1RO8: Inservice Inspection Activities

54-ISI-100-14 Remote Ultrasonic Examination of Reactor Head Penetrations (Areva Document)
NDE-5730-CC Rev 2 - Unit 2 Mode 3 Boric Acid Walkdown
MN-3-301 Rev 4 - Boric Acid Corrosion Inspection Program
MN-3-105, Rev 4. Qualification of Nondestructive Examination Personnel and Procedures.
NDE-5732-CC Rev 3 - Unit 2 Mode 5/6 Boric Acid Walkdown
54-ISI-367-07 - Visual Examination of Leakage of Reactor Head Penetrations
Reactor Head Nozzle Penetration Remote Visual Inspection Plan for Calvert Cliffs Unit 2, Rev 01 (Areva Document)
NDE-5710-CC - Visual Examination(VT-2) for Leakage, Rev 7
Calvert Cliffs Nuclear Power Plant Response to NRC Bulletin 2004-1
Calvert Cliffs Nuclear Power Plant Response to NRC Request for Additional Information for NRC Bulletin 2004-1
Calvert Cliffs Nuclear Power Plant Unit 2 2005 Effective Degradation Years Calculation
Calvert Cliffs Nuclear Power Plant 60 Days After Plant Restart Report NRC Order EA-03-009
ASME Code Case 578-1
Framatome ANP INC., Baseline Dent Data from 21 and 22 Steam Generators 2002
FANP FDMS Map, Bobbin data for tube wear in U-Tube regions of 21/22 Steam Generators for RF015
Calvert Cliffs Unit 1 & 2 SG Eddy Current Data Analysis Guidelines 2005
Calvert Cliffs Nuclear Plant Unit 2 Steam Generator Degradation Assessment, Areva Document Identifier 51-5055434-00
CCNPP U2R15 Eddy Current Approved Analyst List
RCS Letdown Nozzle Weld Overlay Drawing
CCNP-04Q-02 - Standard Weld Overlay Design Drawing
WPS-01-08 T-801, Rev. 3
Calvert Cliffs UFSAR, Section 4.1
Training for Boric Acid Evaluations by K. Hoffman
Alloy 600 at CCNPP - “Partial Penetration Welded Nozzles and Dissimilar Metal Butt Welds”

Boric Acid Walkdown

MO#2200402928 - Boric Acid Indications in the Unit 2 Containment
IRE-003-401 - During U-2 Boric Acid Walkdown In-Active Boric Acid Leaks were identified
Unit 2 RFO SD Boric Acid Walkdown Report dated February 23, 2005

Section 1R12: Maintenance Effectiveness

Crosby Relief Valve Recurring Test Failures

IRE-002-697,1RV132 Failed STP-31-0. Valve would not lift during test.
IRE-002-700, 1RV133 Failed STP-31-0. Valve would not lift during test.
IRE-002-654, 1RV125 Failed STP-31-0. Valve lifted high at 142 psig
MO# 1200303457, Perform STP-031-0 on relief valve 1-RV-132
MO# 1200403396, Perform STP-031-0 on relief valve 1-RV-133
MO# 1200204385, Perform STP-031-0 on relief valve 1-RV-125
STP-31-0, Relief valve testing and setting - Multiple Valves
Maintenance Rule Scoping Document for Chemical and Volume Control
Piping documents, Calvert Cliffs Unit 1 & 2 - Constellation Nuclear - 601 Piping Class Summary Sheets
Pump Manual, Boric acid Pump Flow Curves
Memorandum, Memo from Maintenance and component engineering about change in frequency of relief valve testing (1999)
IR1999901106, Action Item tracking report as a follow up for the initial corrective actions taken for the relief valves.
POSRC Form, Closing of OI 99-079-01 related to relief valve failures. (2000)
POSRC Form, POSRC outstanding Item 01-064-01
IR200200504, Action item dealing with the unacceptable surveillance test failure rate for boric acid system thermal relief valves. (2002)
Memorandum, Memo from Maintenance and component engineering. (2002)
POSRC Form, A summary of the corrective actions that have been agreed upon.
Email, A letter from Chris Jones to Ron Cameron detailing the fact that thermal relief valves can not be relied upon. (2003)
PM change request, Request to change the period for relief valve testing from 24 months to 18 months.
STP-65N-1, 11 Saltwater subsystem valve quarterly operability test (Stroke Times)

2A EDG jacket cooling water leak through cracked compression fitting

IRE-002-742, The 2A DG has developed a jacket cooling water leak at a compression fitting
IRE-002-768, The 2A EDG scavenging air blower cover on the east end of the engine was leaking oil during the run today
Clearance Order#: 2200500162, Remove the 2A DG from service and repair the leak
Dwg. No. 60727SH0001, Diesel generator cooling water, starting air, fuel, and lube oil
2A DG Operator Logs for 1/6/2005
STP O-8A-2, Test of 2A DG and 4 KV Bus 21 LOCI Sequencer Rev 24

1

3kV (21 Bus) to 4kV (14 Bus) Voltage Regulator Oil Level Indicator Failure

Control room log, Unexpected ALARM at 03/28/2005 20:10, OSO Reports that alarm is Low Liquid Level in TAP Changer Compartment for Voltage Regulator 2H2102REG
1C19-ALM, 13kV & 4kV Essential Feeder Breakers Control Board Alarm Manual
NO-1-206, Alarm Annunciator Control
NO-1-206 Attachment 1, Alarm Annunciator Out of Service Log
IRE-004-690, Received Alarm Window R-13 P-13000-2 and Voltage Regulators.
IR4-013-313, LTC Compartment Alarm in on 2H2101 Regulator.
MO 2200501322, Received Alarm Window R-13 P-13000-2 and Voltage Regulators

2B EDG Air Start Compressor Found Tripped

IRE-003-927, 2-PS-4837 2B EDG East Air Compressor Controller
Control Room Log, 03/07/2005 16:55, 2B DG starting air compressor was returned to service
MO# 2200500777, 2B DG Air Compressor Pressure Switches
Maintenance Rule Scoping Document, Emergency Diesel Generator

Section 1R13: Maintenance Risk Assessment and Emergent Work Control

11 Saltwater Header Flow Indicator Replacement

Rover MO for indication replacement
Unit 1 Reactor Operators Log

21 Containment Air Cooler Fan Cooler Motor Replacement

MO 2200304547 - Remove and replace #21 containment cooling fan motor, install spare motor
MO 2200304546 - Remove and replace #22 containment cooling fan motor, install spare motor
Plant Status Integrated Work Schedule Work Week 0509
Shift Turnover Information Sheet March 4, 2005
NO-1-117, Attachment 9 High Risk Activity Plan
IRE-003-959 - 22 Containment Cooler Motor Space Heater. No amps indicated when checking operable.
E-003 Disconnect/reconnect for motors
Clearance Order 2200400605 System 60 Primary Heat and Vent
Calvert Cliffs Industrial Safety Manual Chapter 7 Confined Space Safe Work Practices Rev. 10

22 Containment Air Cooler Fan Cooler Motor Replacement

MO 2200304547 - Remove and replace #21 containment cooling fan motor, install spare motor
MO 2200304546 - Remove and replace #22 containment cooling fan motor, install spare motor
Plant Status Integrated Work Schedule Work Week 0509
Shift Turnover Information Sheet March 4, 2005
NO-1-117, Attachment 9 High Risk Activity Plan
IRE-003-959 - 22 Containment Cooler Motor Space Heater. No amps indicated when checking operable.
E-003 Disconnect/reconnect for motors

Clearance Order 2200400605 System 60 Primary Heat and Vent
Calvert Cliffs Industrial Safety Manual Chapter 7 Confined Space Safe Work Practices Rev. 10

Section 1R14: Operator Performance During Non-Routine Plant Evolutions and Events

Unit 2 Inadvertent Sluicing of Spent Fuel Pool to Refueling Pool

IRE-003-638, Implemented AOP-6F Due to Slowly Lowering Level in SFP.
AOP-6F, Spent Fuel Pool Cooling System Malfunction
OI-24B section 6.23, 12 SFP Cooling Pump - 12 SFP Cooler - Operation with suction from 21 RFP, North Cavity Discharging to 21 RFP, South Cavity with purification and 11 SFP Cooling pump - 11 SFP cooler - Operation with Suction on 11 Discharging to 21 SFP.
SFP Parameters, Licensee information on SPF levels.
Drawing FSK-MP-729, Spent Fuel Cooling Pumps 11 & 12 Suction & Discharge Siphon Break Piping.
Drawing 12530A-14, Area #16 Spent Fuel Cooling.
Drawing 64314, Spent Fuel Pool Cooling, Fill & Purification.
Drawing 60716, Spent Fuel Pool Cooling. Pool Fill & Drain Systems.

Inadvertent Draining Of the Refueling Pool During 21A RCP Maintenance Activities

Control room log on 03/08/2005 at 01:25, Isolation could not be obtained for working 2RC-139 & 140, as the penetration was below the current reduced inventory level (approx. 38').
Control room log on 03/08/2005 01:32, narrative of events surrounding the discovery of a slowly lowering RCS level that resulted in a loss of ½ inch RCS level by GEMS.
IRE-003-997, RCS level was too high to support replacement of 2-RC-139 and 140 under MO 2200302013.
Prompt Investigation, Prompt Investigation information package for IRE-003-997
Email from Tim Riti, Correction of IR which stated incorrect level decrease.
MO# 2200302013, Replace Valves 2HVRC-140/139 Assemblies
OP-7, Shutdown Operation
AOP-3B, Abnormal Shutdown Cooling Conditions
MN-1-101, Control of Maintenance Activities
NO-1-112, Safety Tagging
Clearance 2200400253, Clearance order on the work for the RCP drain valves
Clearance Stub 2200302013-A1, Clearance Stub authorizing work on the drain valves, and presenting a RCS Level boundary of < 38' 6"
Dwgs. FSK-MP-3199, Differential Pressure Indicators on RC Pump #21A
FSK-MP-1312, Typical Arraignment for Differential Pressure Indicators on RC Pumps 11A, 11B, 12A, & 12B
62170SH0003, Component Cooling System
62729SH0001, Reactor Coolant System

Unit 1 Reactor Trip

Unit 1 Reactor Operators Log
Unit 1 Reactor Transient Graphs

Unit 1 Ground Detection Alarm

EP-1-108, Severe Weather Preparation Revision 0
ERPIP 3.0, Attachment 20, Severe Weather
OI-22K, Turbine Building Ventilation Revision 2
Unit 1 Reactor Operators Log
IRE-002-500, Received annunciator A-54 Main Generator Field Ground Alarm
MO#1200500064, Generator Field Ground Detection Annunciator
DWG 61077ASH399, Block Diagram CST No. 12 Level Instrument Loops L5610 and L5611

Unit 2 Reactor Rapid Downpower

Unit 2 Reactor Operators Log
OI-14A, Circulating Water
AOP-7L, Circulating Water/Intake Malfunctions
OP-3, Normal Power Operation
IRE-004-463, Travelling Screen Indication at 2C13 in the Control Room has failed
SRW and Miscellaneous Station Services Alarm manual 2C13-ALM page 52 of 70, "Travelling Screen Differential Pressure HI"

Section 1R15: Operability Evaluations

Potential degradation of Fairbank Morse EDG due to infrequent Unit 1 SRW pump alignment

IRE-002-167, STP O-73B has a sequence of steps that violated a general precaution of OI-15
IRE-002-963, Section 6.3.C of OI-15-1 violates OI-15 general precaution
OI-15-1, Service Water System - Unit 1
OI-15-2, Service Water System - Unit 2
STP O-73B-1, Service Water Pump Quarterly Test - Unit 1
STP O-73B-2, Service Water Pump Quarterly Test - Unit 2
Loading Test Page, 2ZB Loading Sequence Voltage Profile - As Sequenced
Daily Event log, Utilized OI-15 6.3.C to shift 13 SRW Pp from 11 4Kv bus to 12 Header and 14 4Kv bus
Basis B0857, Basis providing an explanation on the proper operation of the swing SRW pumps.
ES199700364, Action item for reviewing and correcting any procedure changes to uphold Basis B0857
Calvert Cliffs UFSAR, Chapter 8, Electrical Systems, Section 8.4.1 Fairbanks Morse Emergency Diesel Generators
Regulatory Guide 1.9, Revision 3, Selection, Design, Qualification, and Testing of Emergency Diesel Generators Units Used as Class 1E Onsite Electrical Power Systems at Nuclear Power Plants.
NS-2-101 POSRC/PRC Presentation Form, Information Packet discussing instance where EDG was overloaded in 1995

1A EDG Disconnected Starting Air Line

IRE-003-014, Found start air line bolt loose at 1A1 A2 Cylinder start air valve.

UFSAR Vol.3, Chapter 8, Electrical System chapter describing the needed amount of starting air headers for the EDG to be operable.
MO# 1200500419, Reinstall airline bolt on 1A1 A2 Airline. Verify tightness on all airline bolting for 1A1, 1A2, OC1, AND OC2

Impact of Crosby Relief Valve Test Failures on Unit 1 and 2 Saltwater System Operabilty

IRE-002-697, 1RV132 Failed STP- 31-0. Valve would not lift during test.
IRE-002-700, 1RV133 Failed STP-31-0. Valve would not lift during test.
IRE-002-654, 1RV125 Failed STP-31-0. Valve lifted high at 142 psig
MO# 1200303457, Perform STP-031-0 on relief valve 1-RV-132
MO# 1200403396, Perform STP-031-0 on relief valve 1-RV-133
MO# 1200204385, Perform STP-031-0 on relief valve 1-RV-125
STP-31-0, Relief valve testing and setting - Multiple Valves
Maintenance Rule, Scoping Document for Chemical and Volume Control
Piping documents, Calvert Cliffs Unit 1 & 2 - Constellation Nuclear - 601 Piping Class Summary Sheets
Pump Manual, Boric acid Pump Flow Curves
Memorandum, Memo from Maintenance and component engineering about change in frequency of relief valve testing (1999)
IR1999901106, Action Item tracking report as a follow up for the initial corrective actions taken for the relief valves.
POSRC Form, Closing of OI 99-079-01 related to relief valve failures. (2000)
POSRC Form, POSRC outstanding Item 01-064-01
IR200200504, Action item dealing with the unacceptable surveillance test failure rate for boric acid system thermal relief valves. (2002)
Memorandum, Memo from Maintenance and component engineering. (2002)
POSRC Form, A summary of the corrective actions that have been agreed upon.
Email, A letter from Chris Jones to Ron Cameron detailing the fact that thermal relief valves can not be relied upon. (2003)
PM change request, Request to change the period for relief valve testing from 24 months to 18 months.
STP-65N-1, 11 Saltwater subsystem valve quarterly operability test (Stroke Times)

21 AFW Pump low oil level in turbine inboard bearing sightglass

IRE-004-237 - 21 AFW Feedwater Pump was tripped due to low oil level on the turbine inboard bearing.
RECO associated with IRE-004-237
OI-32A-2 Auxiliary Feedwater System

2A EDG Failure Of Compression Fitting In The Jacket Water System

IRE-002-742, The 2A DG has developed a jacket cooling water leak at a compression fitting
IRE-002-768, The 2A EDG scavenging air blower cover on the east end of the engine was leaking oil during the run today
Clearance Order 2200500162, Remove the 2A DG from service and repair the leak
Dwg. No. 60727SH0001 - Diesel generator cooling water, starting air, fuel, and lube oil

2A DG Operator Logs for ½6/2005
STP O-8A-2, Test of 2A DG and 4 KV Bus 21 LOCI Sequencer Rev 24

<u>2B EDG Air Start Compressor Found Tripped</u>

IRE-003-927, 2-PS-4837 2B EDG East Air Compressor Controller
Control Room Log, 03/07/2005 16:55, 2B DG starting air compressor was returned to service
MO# 2200500777, 2B DG Air Compressor Pressure Switches
Maintenance Rule Scoping Document, Emergency Diesel Generator

<u>Unit 2 Reactor Coolant System Alloy 600 Weld Defects</u>

NO-1-106, Attachment 7, Basis For Reasonable Expectation Of Continued Operabiity (RECO), dated 2/28/05
IRE-003-574, Axial flaw on 22A cold leg letdown line
IRE-003-469, Circumferential flaws identified on the hot leg
AIT# ES200500115 MS-3, Weld inspection plan for Unit 2, 2006 outage

<u>Section 1R16: Operator Workarounds</u>

<u>12B RCP Lower Seal Temperature Sensor Failed</u>

Operations Administrative Policy (OAP), 2004-01, Managing Operator Impacts
NO-1-206, Alarm Annunciator Control
1C06-ALM, RCS Control Alarm Manual
IR4-002-537, Received 12B RCP seal temperature/pressure alarm several times
MO#: 1200500168, Troubleshoot/replace 12B RCP seal temperature high/pressure alarm
MO#: 1200405670, 12BRCP lower seal temperature is erratically alarming high

<u>2-CVC-325 Inaccurate Position Indication Due To Faulty Limit Switch</u>

Operations Administrative Policy (OAP), 2004-01, Managing Operator Impacts
Unit 2 Reactor Operators Log
Unit 2 Shift Turnover Sheet, Compensatory Actions Section
MO#2200500350 - Repair ground at 2 CVC L/D inlet to purifier filter

<u>Section 1R17: Permanent Plant Modifications</u>

<u>21 AFW Pump Forced Oil System Installation</u>

MO# 2200102368 - Implement the forced oil modification on the 21 AFW turbine IAW ES 200100565
ES 200100565 - 21 AFW Pump Forced OIL Modification Package
IRE-004-237 - 21 AFW Feedwater Pump was tripped due to low oil level on the turbine inboard bearing.
RECO associated with IRE-004-237
OI-32A-2 Auxiliary Feedwater System

<u>Section 1R19: Post-Maintenance Testing</u>

<u>23 HPSI Breaker, Motor, and Controls Inspection</u>

MO#: 2200403254, 23 HPSI pump breaker, motor, and controls inspection
FTE-59, Periodic Maintenance, Calibration And Functional Testing Of Protective Relays

<u>22 Component Cooling Water Heat Exchanger Cleaning</u>

MO#: Clean 22 Component cooling water heat exchanger
Clearance ID#: 2200400728, Tagout for cleaning the 22 CCHX
Drawing: OM-450SH0002
OI-29, Saltwater System
NO-1-203, Operations Performance Evaluation Requirements

<u>22 Containment Spray Pump Breaker MH and MJ Switch Replacements</u>

MO#: Replace MH and MJ switches on the 22 containment spray pump breaker
IR4-021-233, Replace MH and MJ switches with Lexan switches
HU-1-102, Brief Leader Preparation

<u>21 Containment Air Coolers following fan motor replacement</u>
MO 2200304547 - Remove and replace #21 containment cooling fan motor, install spare motor
MO 2200304546 - Remove and replace #22 containment cooling fan motor, install spare motor
Plant Status Integrated Work Schedule Work Week 0509
Shift Turnover Information Sheet March 4, 2005
NO-1-117, Attachment 9 High Risk Activity Plan
IRE-003-959 - 22 Containment Cooler Motor Space Heater. No amps indicated when checking operable.
E-003 Disconnect/reconnect for motors
Clearance Order 2200400605 System 60 Primary Heat and Vent
Calvert Cliffs Industrial Safety Manual Chapter 7 Confined Space Safe Work Practices Rev. 10

<u>22 Containment Air Coolers Following Fan Motor Replacement</u>

MO 2200304547 - Remove and replace #21 containment cooling fan motor, install spare motor
MO 2200304546 - Remove and replace #22 containment cooling fan motor, install spare motor
Plant Status Integrated Work Schedule Work Week 0509
Shift Turnover Information Sheet March 4, 2005
NO-1-117, Attachment 9 High Risk Activity Plan
IRE-003-959, 22 Containment Cooler Motor Space Heater. No amps indicated when checking operable.
E-003 Disconnect/reconnect for motors
Clearance Order#: 2200400605, System 60 Primary Heat and Vent
Calvert Cliffs Industrial Safety Manual Chapter 7 Confined Space Safe Work Practices Rev. 10

2A EDG Following Jacket Cooling Water Line Replacement

IRE-002-742, The 2A DG has developed a jacket cooling water leak at a compression fitting
IRE-002-768, The 2A EDG scavenging air blower cover on the east end of the engine was leaking oil during the run today
Clearance Order#: 2200500162, Remove the 2A DG from service and repair the leak
Dwg. No. 60727SH0001, Diesel generator cooling water, starting air, fuel, and lube oil
2A DG Operator Logs for January 26, 2005
STP O-8A-2, Test of 2A DG and 4 KV Bus 21 LOCI Sequencer Rev 24

Section 1R20: Refueling and Outage Activities

Review of Outage Plan

Critical Outage Activities Listing
High-Level Outage Schedule

Monitoring of Shutdown Activities

PSTP-10, Coastdown Procedure
Unit 2 Cycle 15 Coastdown Figure (2)
OP-3, Normal Power Operation
OP-4, Plant Shutdown from Power Operation to Hot Standby
OP-5, Plant Shutdown from Hot Standby to Cold Shutdown
OP-5, Appendix 1, RCS Cooldown Log
RCS P/T Limits 3.4.3, Figure 3.4.3-2

Licensee Control of Outage Activities

IRE-003-997, RCS level was too high to support replacement of 2-RC-139 and 140 under MO 2200302013.
MO# 2200302013, Replace Valves 2HVRC-140/139 Assemblies
OP-7, Shutdown Operation
AOP-3B, Abnormal Shutdown Cooling Conditions
MN-1-101, Control of Maintenance Activities
NO-1-112, Safety Tagging
Clearance 2200400253, Clearance order on the work for the RCP drain valves
Clearance Stub 2200302013-A1, Clearance Stub authorizing work on the drain valves, and presenting a RCS Level boundary of < 38' 6"
Dwgs. FSK-MP-3199, Differential Pressure Indicators on RC Pump #21A
FSK-MP-1312, Typical Arraignment for Differential Pressure Indicators on RC Pumps 11A, 11B, 12A, & 12B, 62170SH0003, Component Cooling System, 62729SH0001, Reactor Coolant System

Reduced Inventory and Mid-Loop Conditions

IRE-003-638, Implemented AOP-6F Due to Slowly Lowering Level in SFP.
AOP-6F, Spent Fuel Pool Cooling System Malfunction

OI-24B section 6.23, 12 SFP Cooling Pump - 12 SFP Cooler - Operation with suction from 21 RFP, North Cavity Discharging to 21 RFP, South Cavity with purification and 11 SFP Cooling pump - 11 SFP cooler - Operation with Suction on 11 Discharging to 21 SFP.
SFP Parameters, Licensee information on SPF levels.
Drawing FSK-MP-729, Spent Fuel Cooling Pumps 11 & 12 Suction & Discharge Siphon Break Piping.
Drawing 12530A-14, Area #16 Spent Fuel Cooling.
Drawing 64314, Spent Fuel Pool Cooling, Fill & Purification.
Drawing 60716, Spent Fuel Pool Cooling. Pool Fill & Drain Systems.

<u>Refueling Activities</u>

Fuel Handling Procedure 305, “Core Alterations”, Rev. 7.
NO-1-100, “Conduct of Operations”
OI-25A, “Spent Fuel Handling Machine”
OI-25C, “Refueling Machine”

<u>Monitoring of Heatup and Startup Activities</u>

PSTP-02, Initial Approach to Criticality and Low Power Physics Testing Procedures
IRE-004-250, 2-PS-400 Active lead coming from drain plug
IRE-004-263, 2-RC-1040 Active packing lead
IRE-004-264, 2-RC-1047 Active boric acid leak on packing/bonnet
IRE-004-271, 2-SI-524 Active boric acid leak at end of tubing
IRE-004-272, 2-SI-525 Active boric acid leak at end of tubing
IRE-004-256, 2-FW-1630 Packing leak
IRE-004-266, 2-FW-1517 Packing leak
IRE-004-267, 2-FW-1537 Packing leak
IRE-004-269, 2-CC-376 Leak at pipe cap
IRE-004-276, 2-FW-1530 Packing leak

<u>Section 1R22: Surveillance Testing</u>

<u>21 ECCS Air Cooler Outlet Valve Stroke Time Test</u>

Control Room Log, 02/17/2005 05:33, During the performance of STP O-65N-2, 2-SW-5171-CV stroked shut in the inoperable range.
STP O-65N-2, 21 Saltwater Subsystem Valve Quarterly Operability Test.
IRE-003-289, 2-SW-5171-CV did not indicate full open in the control room during the performance of STP-O-65N-2 Section 6.2. The valve indicated fully open locally

<u>21 AFW Quarterly Surveillance Test</u>

STP O-5A-2, “AFW Quarterly Surveillance Test”

Section 1R23: Temporary Plant Modifications

11A Reactor Coolant Pump CCW Lo Flo Alarm Disabled Due To Degraded Flow Switch With Proper CCW Flow

MO#1200403209 - Repair/replace 1FS3835, RCP 11A CC Flow, Clear Temp Alt 1-05-0008
IR4-033-963 - Received annunciator E-49. Along with X-02 (CCW Flow Lo). All temp parameters associated with 11A RCP remained stable and all component cooling system parameters were normal.
Temporary Alteration#1-05-0008, Lift Leads at 1K03 to remove hanging alarm

Temporary Alteration No. 1-05-0003, Jumpering Out 12B RCP Lower Seal Temperature Failed Element 1TE181

Temporary Alteration Form No. 1-05-0003, Jumper out failed temperature element 1TE181
MO#: 1200500168, 1TE181 failed/unreliable. Troubleshoot/repair
IRE-002-537, 1TE181 is not reliable
Drawing 60933SH0022A, Loop diagram 12B reactor coolant pump seal temperature & pressure

Temporary Alteration No. 2-03-0019, Open Breaker 52-20446 associated with 2-RC-403-MOV

MO# 2200302439, Install T/A 2-03-0019 on 2MOV403OP, Remove T/A 2-03-0019 and VOTES Test
MO# 2200304779, Votes test and MOV-13 on 2MOV405OP
IR4-018-598 - 2RC403 MOV PORV Block Valve failed to indicate full shut during the performance of STP O-65H-2

Defeating of a nuisance alarm associated with the 13kV (21 Bus) to 4kV (14 Bus) voltage regulator failed oil level instrument

Control room log, Unexpected ALARM at 03/28/2005 20:10, OSO Reports that alarm is Low Liquid Level in TAP Changer Compartment for Voltage Regulator 2H2102REG
1C19-ALM, 13kV & 4kV Essential Feeder Breakers Control Board Alarm Manual
NO-1-206, Alarm Annunciator Control
NO-1-206 Attachment 1, Alarm Annunciator Out of Service Log
IRE-004-690, Received Alarm Window R-13 P-13000-2 and Voltage Regulators.
IR4-013-313, LTC Compartment Alarm in on 2H2101 Regulator.
MO 2200501322, Received Alarm Window R-13 P-13000-2 and Voltage Regulators

Section 1EP4: Emergency Action Level (EAL) and Emergency Plan (E-Plan Revision

Calvert Cliffs Emergency Plan and Implementing Procedures

Section 2OS1: Access Control to Radiologically Significant Areas:

SWP 2005-2002, Rev. 0, ISI/NDE Activities for Unit 2 RFO (Includes alloy 600 inspections)
SWP 2005-2005, Rev. 2, NDE exams/weld repairs for alloy 600 as approved by radiological engineering

SWP 2005-2309, Rev. 1, In-core instrumentation (ICI) change outs during the U-2 refueling outage
SWP 2005-2324, Rev. 0, Volumetric inspections under reactor head
SWP 2005-2325, Rev. 0, Visual inspections of external reactor head
SWP 2005-2401, Rev. 1, Reactor coolant pump (RCP) seal replacements during the U-2 refueling outage
SWP 2005-2409, Rev. 2, Steam generator eddy current, tube plugging, and manipulator installation/removal during the U-2 refueling outage
Procedure RSP-1-104, Rev. 18, Area posting and barricading
Procedure RSP-1-107, Rev. 7, Personnel contamination assessment/decontamination
Procedure RSP-1-132, Rev. 9, Job coverage in radiologically-controlled areas
Procedure RSP-1-200, Rev. 22, ALARA planning and SWP preparation

Section 2OS2: ALARA Planning and Controls

ALARA review for SWP 2005-2005, Activities 1 - 4, Rev. 2, Alloy 600 emergent work, February28, 2005
ALARA in-process review for SWP 2005-2000, Activity 1, Rev. 0, Health physics activities, February 28, 2005
ALARA in-process review for SWP 2005-2002, Activity 2, Rev. 0, Inspect/NDE on alloy 600 transition weld areas, February 28, 2005
ALARA in-process review for SWP 2005-2005, Activities 2 - 4, Rev. 2, Emergent work supporting alloy 600 inspections, February 28, 2005
ALARA in-process review for SWP 2005-2016, All activities, Rev. 1, Scaffold/insulation activities for the U2 refueling outage, February 25, 2005
ALARA in-process review for SWP 2005-2310, Activities 1 - 4, Rev. 0, Refueling activities, February 28, 2005
ALARA in-process review for SWP 2005-2412, Activity 1, Rev. 0, Weld overlay of alloy 600 transition on the nozzle on 21 S/G hot leg drain line, March 1, 2005
Procedure RP-1-101, Rev. 3, ALARA
Procedure RSP-1-200, Rev. 22, ALARA planning and SWP preparation INFOWORKS Refueling Outage SWP listing of current doses, dose estimates, and percentages of estimates for March 4, 2005
Dose intervention plans for the 2005 refueling outage, February 25, 2005

Section 2OS3: Radiation Monitoring Instrumentation and Protective Equipment

Procedure RSP 1-102, Rev. 19, Pre-operational checks of the portable survey equipment

Section 4OA3: Event Followup

Unit 1 Reactor Trip
Unit 1 Reactor Operators Log
Unit 1 Reactor Transient Graphs

LIST OF ACRONYMS

AFW	Auxiliary Feedwater
ALARA	As Low As Reasonably Achievable
ASME	American Society of Mechanical Engineers
CAP	Corrective Action Program
CC	Component Cooling
CDF	Core Damage Frequency
CEDE	Committed Effective Dose Equivalent
CEDM	Control Element Drive Mechanism
CFR	Code of Federal Regulations
CST	Condensate Storage Tank
CWP	Circulating Water Pump
DAC	Derived Air Concentration
EAL	Emergency Action Level
EDG	Emergency Diesel Generator
EP	Emergency Preparedness
EPD	Electronic Personal Dosimeter
ERPIP	Emergency Response Plan Implementation Procedure
ESFAS	Engineered Safety Features Actuation System
FME	Foreign Material Exclusion
HIT	High Impact Team
HP	Health Physics
HPSI	High Pressure Safety Injection
HRA	High Radiation Area
ICI	In-Core Instrumentation
IEL	Initiating Event Likelihood
IR	Issue Report
LHRA	Locked High Radiation Area
LOCA	Loss of Coolant Accident
LOI	Loss of Inventory
LOOP	Loss of Offsite Power
LPSI	Low Pressure Safety Injection
NCV	Non-Cited Violation
OAP	Operations Administration Policy
OS	Occupational Safety
PI	Performance Indicator
PTL	Pull-To-Lock
PWSCC	Primary Water Stress Corrosion Cracking
RCA	Radiologically-Controlled Area
RCS	Reactor Coolant System
RCP	Reactor Coolant Pump
RFO	Refueling Outage
RFP	Refueling Pool
RP	Radiation Protection
RPV	Reactor Pressure Valve
RSP	Radiation Safety Procedure
SACM	Societe Alsacienne de Constructions Mecaniques

SDC	Shutdown Cooling
SDP	Significance Determination Process
SFP	Spent Fuel Pool
SRW	Service Water System
SSC	Systems, Structures and Components
SWP	Special Work Permit
TI	Temporary Instruction
TS	Technical Specifications
UT	Ultrasonic
UV	Visual
VHP	Vessel Head Penetration
UFSAR	Updated Final Safety Analysis Report
VHRA	Very High Radiation Area
WANO	World Association of Nuclear Operators