U. S. NUCLEAR REGULATORY COMMISSION
Region I

Docket Nos.: 50-317 / 50-318

License Nos.: DPR-53 / DPR-69

Report Nos.: 50-317/89-18 / 50-318/89-19

Licensee: Baltimore Gas and Electric Company
Post Office Box 1475
Baltimore, Maryland 21203

Facility: Calvert Cliffs Nuclear Power Plant, Units 1 and 2

Inspection at: Lusby, Maryland

Inspection Conducted: July 4 - August 28, 1989

Inspectors: D. Limroth, Acting Senior Resident Inspector
V. Pritchett, Resident Inspector

Approved By: Lowell E. Tripp — 10/24/89
Lowell E. Tripp, Chief — date
Reactor Projects Section No. 1A

Summary: July 4 - August 28, 1989 Inspection Report Nos. 50-317/89-18 and 50-318/89-19

Areas Inspected: Facility activities, licensee action on previous inspection findings, operational safety, physical security, plant operations, maintenance, surveillance, engineering support, Licensee Event Reports, licensee response to NRC initiatives, review of periodic and special reports, and events requiring notification to the NRC.

Results: The licensee continued to investigate pressurizer heater failure mode and evaluate several alternate repair schemes (see Section 6.1). The licensee failed to establish adequate controls and procedures for the Fire Protection System resulting in a failure to satisfy Technical Specification requirements (see Section 7.1). A fractured nut from a Unit 2 Steam Generator snubber assembly was analyzed and the entire issue resolved with proper safety perspective (see Section 7.2). A reserve battery surveillance was missed, but fortuitously, the plant was not in a mode where the battery was required (see Section 7.2). The reactor coolant system was overfilled due to a failure to follow procedure (see Section 7.2). The licensee failed to recognize a surveillance requirement to test both Spent Fuel Ventilation Exhaust Fans which resulted in a failure to meet Technical Specification Surveillance Requirements (see Section 7.2).

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*The NRC Inspection Manual inspection procedure (IP) or the Region I temporary instruction (RTI) that was used as inspection guidance is listed for each applicable report section.

DETAILS

1. Persons Contacted

Within this report period, interviews and discussions were conducted with various licensee personnel, including reactor operators, maintenance and surveillance technicians and the licensee's management staff. Night shift inspections were conducted on July 5, 11, 17, [illegible] 20, 27, August 3 and 17, 1989.

Weekend inspections were conducted on July 8, 9, 22 and 23, 1989.

2. Summary of Facility Activities

Unit 1

The unit was shutdown the entire period pending the results of the Unit 2 pressurizer heater investigation.

Unit 2

The unit was shutdown for the entire period for a combination of the 8th cycle scheduled refueling outage and the continuing investigation and repairs of the pressurizer heaters.

The unit is expected to remain shutdown through March 1990.

General

Region I specialist inspection personnel performed inspections during the following periods:

-- Week of July 10, 1989, covering pressurizer heater work and emergency response.

-- Week of July 17, 1989, covering diesel fuel oil quality.

-- Week of August 7, 1989, covering compliance to Regulatory Guide 1.97.

-- Week of August 28, 1989, covering procurement and quality control.

Defueling operations were completed on Unit 2 on July 5, 1989.

The licensee met with the NRC at NRC Headquarters on August 4, 1989, to discuss the Performance Improvement Plan for Calvert Cliffs, Units 1 and 2.

On July 18, 1989, USNRC Commissioner Kenneth C. Rogers toured the facility.

The licensee met with the NRC in King of Prussia, Pennsylvania, on July 20, 1989, for an Enforcement Conference resulting from the findings of Combined Inspection Report Nos. 50-317/89-15 and 50-318/89-16, and Special Team Inspection Report Nos. 50-317/89-200 and 50-318/89-200.

The licensee met with the NRC in King of Prussia, Pennsylvania, on August 28, 1989, to discuss the status of the licensee's effort on Fire Protection/Appendix R Design Basis Consolidation.

The licensee met with the NRC's Calvert Cliffs Assessment Panel at the Calvert Cliffs facility on August 28, 1989, to review the Performance Improvement Plan.

3. Licensee Action on Previous Inspection Findings

3.1 (Closed) Unresolved Item (50-317/88-28-02; 50-318/88-28-02): Deficiencies in licensee's NCR program in the area of determination that regulatory reporting requirements have been met for identified nonconforming conditions. In response to the Notice of Violation in Combined Inspection Report Nos. 50-317/88-28; 50-318/88-28, the licensee stated that procedures would be properly screened for reportability requirements. The inspector has reviewed Quality Assurance Procedure (QAP) 26, "Control of Conditions Adverse to Quality," Revision 41, dated April 28, 1989, and found the issue of reportability adequately covered by the document. In addition, the inspector reviewed Calvert Cliffs Instruction (CCI) 116, "Control of Deficiencies and Nonconformance Reports," Revision G, effective August 23, 1989. The CCI has been revised to include structured steps addressing reportability assessment. The changes force a detailed look at reportability of nonconforming conditions. This item is closed.

3.2 (Closed) Unresolved Item (50-317/88-32-03): Auxiliary Feedwater System header isolation check valve 1-MS-103 inoperable. The licensee has completed their analysis and corrective action plan. The metallurgical laboratory has determined that the materials used in the hinge pins and bushings of the valve were as specified by design. The licensee's engineering consultant has determined that the hinge pins and bushings showed wear patters representative of mechanical wear as opposed to corrosion. The valve manufacturer, Anchor/Darling, has suggested changing the bushing material. However, the engineering consultant believes that changing the bushing material might extend the valve service life, but the root cause of failure (i.e., extended periods of banging) would continue to cause premature valve failure. A Facility Change request has been initiated which will change the orientation of 1-MS-103 and 1-MS-106 from vertical to horizontal, place them at least four pipe diameters from the nearest pipe configuration change and install a downstream manual isolation valve. These changes prevent water buildup and provide for maintenance access and testing. Testing with various material combinations for check valve bushings and hinges will begin as soon as steam is available for the testing. The licensee has addressed the concerns raised by the inspector. This item is closed.

3.3 (Closed) Unresolved Item (50-318/88-06-01): High Spray Line/Pressurizer Differential Temperature. The licensee addressed their corrective actions in a letter dated June 17, 1988. The inspector has verified that discussions of the event with each operating crew were completed emphasizing the need for maintaining a questioning attitude during all plant evolutions. The licensee has revised Operating Procedure (OP)-6, "Pre-Startup Checkoff," Attachment 1A to insure proper positioning of the pressurizer spray bypass valves.

The licensee has decided that no further training is required. They believe that the combination of the initial operator training and discussions held with operating crews represents appropriate corrective action scope and detail to insure an adequate level of alertness. The licensee has addressed the concerns raised by the inspector. This item is closed.

3.4 (Closed) Violation (50-317/88-07-04): Concerns relative to temporary changes made to surveillance test procedures. The licensee has revised Calvert Cliffs Instruction (CCI) 101L, "Calvert Cliffs Implementing Procedure Development and Control," dated July 18, 1989, which includes detailed information on "changes of intent" to procedures. The inspector has reviewed CCI-101L and has determined that the licensee has addressed the concerns raised by the violation and the inspector. This item is closed.

3.5 (Closed) Unresolved Item (50-317/89-07-01 and 50-318/89-07-01): Concerns on document control control and validation of placards used by operators. The inspector has verified that subsequent to the inspection, the licensee has revised CCI-308C, "Temporary Notes, Operator Aids, and Permanent Labels," dated June 2, 1989, to include the "mimics and placards" in the Operator Aid Program. This would include a review by the Shift Supervisor/Outage Management Coordinator prior to issuance and a quarterly audit to verify applicability. The initial review and approval will be documented and maintained in the Operator Aid Log located in the Shift Supervisor's office along with the quarterly audit record. The licensee has satisfactorily addressed concerns raised by the inspector. This item is closed.

3.6 (Closed) Violation (50-317/87-11-03 and 50-318/87-12-03): Records involving Special Nuclear Material (SNM). The inspector has reviewed the changes made to CCI-507G, "Special Nuclear Material Accounting Procedure," dated September 9, 1988. The new CCI-507G has been updated to require a physical inventory performed every 6 months. Detailed instructions were added to explain what is expected from the inventory. An independent checker was also added to compare the maps from the physical inventory to the computer data base and card file information. After the physical inventory and computer data base/card file has been reconciled, a SNM inventory report is generated to summarize the results. The persons involved in the physical inventory and independent check sign the report along with the Principal Engineer - Nuclear Engineering Unit. All maps, computer printouts and any other paperwork generated for the inventory are collected and placed in the Nuclear Engineering Unit's filing system. CCI-507G has also been changed to reflect that a DOE/NRC Form 741 shall be filled out when a SNM transfer involves a change in Reporting Identification Symbol (RIS). This item is closed.

3.7 (Closed) Unresolved Item (50-317/88-11-02): Lack of information on qualification records of Fuel Cycle Management (FCM) personnel. The inspector has reviewed the experience records of all FCM personnel to verify that all records have been updated and include required information. The licensee has addressed the concerns raised by the inspector. This item is closed.

4. Operational Safety

4.1 Daily Inspection

During routine facility tours, the following were checked: manning, access control, adherence to procedures and LCO's, instrumentation, recorder traces, protective systems, control rod positions, containment temperature and pressure, control room annunciators, radiation monitors, effluent monitoring, emergency power source operability, control room logs, shift supervisor logs, and operating orders.

No unacceptable conditions were noted.

4.2 System Alignment Inspection

Operating confirmation was made of selected piping system trains. Accessible valve positions and status were examined. Visual inspection of major components was performed. Operability of instruments essential to system performance was assessed. The following systems were checked during plant tours and control room panel status observations:

- Unit 1 Component Cooling System
- Unit 1 Salt Water System
- Diesel Generator Air Start System

No unacceptable conditions were noted.

4.3 Biweekly and Other Inspections

During plant tours, the inspector observed shift turnovers; boric acid tank samples and tank levels were compared to the Technical Specifications; and the use of radiation work permits and Health Physics procedures were reviewed. Plant housekeeping and cleanliness were evaluated.

No unacceptable conditions were noted.

4.4 Bimonthly Safety System Verification

The inspector independently verified the operability of a selected engineered safety features (ESF) system by performing a complete walkdown of the accessible portions of the Unit 1 Low Pressure Safety Injection System to:

-- confirm that the licensee's system lineup procedures match plant drawings and the as-built configurations;

-- identify equipment conditions and items that might degrade performance;

-- verify appropriate levels of cleanliness were being maintained;

-- verify technical specification requirements are adhered to;

-- verify instrumentation lineup and calibration; and

-- verify proper valve position, availability for function and position indication.

No unacceptable conditions were noted.

5. Security

5.1 Observation of Physical Security

Checks were made to determine whether security conditions met regulatory requirements, the physical security plan, and approved procedures. Those checks included security staffing, protected and vital area barriers, vehicle searches and personnel identification, access control, badging, and compensatory measures when required.

No unacceptable conditions were noted.

6. Plant Operations

6.1 Unit 1 and 2 Pressurizer Heater Defects

Following completion of defueling operations on Unit 2, on July 5, 1989, pressurizer heater removal began on July 7, 1989 (see Combined Inspection Report 50-317/89-14 and 50-318/89-14, Section 6.1). Initial visual examination of the Unit 2 heater sleeves showed no defects and by July 17, 1989, 28 of 120 heaters had been removed. Penetrant testing of the Unit 1 sleeves was completed on July 18, 1989; no indications were discovered. On July 21, 1989, a crack was discovered in a Unit 2 sleeve through penetrant examination along with three axial indications in an upper part of the sleeve.

On August 5 and August 7, 1989, Unit 2 and Unit 1 dye penetrant examinations were completed. Unit 2 final NDE results indicated 16 indications in 28 sleeves. There were no indications on Unit 1. For unit 2, a core bore was made at location H3 on August 14, 1989. On the same day, the licensee assigned an overall project manager to the pressurizer project. For Unit 1, two upper portions of sleeves were destructively tested and showed no indications. The removal of Unit 2 heaters was completed on August 26, 1989.

The aforementioned is included as a chronological record of the licensee's efforts. The inspectors have reviewed the licensee work efforts and repair plans with the following observations.

The problem was discovered on May 5, 1989, during in-service inspection. Leakage was indicated by the presence of small amounts of boric acid crystals that collected around the heater penetration in the lower head of the alloy steel pressurizer. Twenty heater penetrations were believed to be leaking and eight others were suspect. Additionally, one of six upper pressure/level penetrations on the pressurizer head was discovered to have leaked. On May 6, Unit 1 was shut down to examine its pressurizer. No leakage was observed from its heater or pressure/level penetrations.

The leaking heater penetrations in Unit 2 were somewhat localized and involved mainly lower level penetrations. The Unit 2 heaters were meggered for low grounds by heater bank groupings. No deficiencies were noted. Combustion Engineering, the nuclear steam supplier for Units 1 and 2, furnished the following information. The transition sleeves, which contain the heaters, were welded to the Inconel cladded I.D. surface of the vessel using a penetration J groove joint configuration. Welding was reportedly performed by the Tungsten Inert Gas (TIG) process using Inconel 82 bare wire. The licensee reported that the sleeves were installed by Combustion Engineering without rolling and the J groove welds were liquid penetrant inspected with a 1/64" indication acceptance criterion. The transition sleeve material for both Unit 1 and 2 pressurizers was furnished by INCO Huntington Alloy Division from one heat of alloy 600 material - heat NX8878. The heaters were manufactured by Wiegand and are contained in an Inconel Alloy 600 sheath (outer cylinder).

The inspector reviewed the certified mill test report (CMTR) for the subject heat and verified its conformance to ASME SB-167 and CE specification P43B4-(b) with respect to metallurgical requirements. The CMTR indicated that the material was furnished in the annealed condition with a hardness of RB 94 and a tensile strength of 103,500 psi. These values appear to be slightly on the high side for the material involved. The CMTR indicated that the material had been subjected to both hydrostatic and ultrasonic testing.

The licensee reported no significant difference in operating or water chemistry control between Units 1 and 2; although, Unit 2 experienced a sulfuric acid intrusion in 1983 because of a failure in the No. 21 purification exchanger. Subsequent to the end of the inspection period, the licensee finished their evaluation of extensive NDE and metallurgical work. They determined that the sleeve cracks were all axial and characterized them as due to Primary Water Stress Corrosion Cracking initiated by high stress imposed on the Unit 2 sleeves through a reaming operation during fabrication. Additional NRC inspection followup and evaluation of this work will be included in future report(s).

At the end of the period, the licensee was investigating several alternative repair schemes such as welding the existing sleeve to a temper bead/half bead Inconel pad on the outside of the SA-533 type B (P3) head, or completely removing the existing sleeve and installing a new sleeve fabricated from a more corrosion resistant material (alloy 690) which would be welded to the I.D. and O.D. of the head. Consideration was being given to the effects of the boron crystals on welding and corrosion of the carbon steel. The final repair procedure will depend on the cause of the leakage and several other factors including the levels of decontamination achieved in Unit 2.

The inspectors will continue to follow the licensee's efforts and will update progress in subsequent reports.

6.2 Unit 2 - Steam Generator Blowdown Line Failure

The inspector reviewed the licensee's failure analysis report of a leaking Unit 2 steam generator carbon steel blowdown line. The report concluded that the failure occurred in a 90° elbow to pipe socket weld in an area of weld undercut that coincided with a region reduced in thickness by erosion. No other metallurgical deficiencies or abnormalities were reported. The inspector concurred with the conclusions of this report. The licensee reported that the entire blowdown system will be replaced in Unit 1 during the present outage. Similar joints were inspected in Unit 1 with no problem areas found.

7. Maintenance/Surveillance

7.1 Maintenance

The inspector observed and reviewed maintenance and problem investigation activities to verify compliance with regulations, administrative and maintenance procedures, codes and standards, proper QA/QC involvement, safety tag use, equipment alignment, jumper use, personnel qualifications, fire protection, retest requirements, and reportability per Technical Specifications.

The following activities were included:

- Maintenance Order (MO) No. 209-073-027B, perform alignment on No. 12 Containment Spray Pump.
- MO No. 209-132-132A, perform coupling alignment check on No. 23 charging pump.
- MO No. 209-082-412A, perform repairs on 1-N2-346 check valve.
- MO No, 209-066-749A, repack gland on #12 Auxiliary Feedwater Pump.
- MO No. 209-215-826A, perform inspection on breaker No. 52-1115.
- MO No. 208-354-587A, perform overhaul of 2-M3-4022-RV.
- MO No. 209-240-433, Main Vent Gases RMS Testing.

-- On July 20, 1989, with Unit 1 in Cold Shutdown, licensee personnel were performing Surveillance Test Procedure (STP) M-291-0, "Halon System Valve Position Verification" when a solenoid was discovered to be disconnected from its associated valve. The solenoid was on the Unit 1 Electrical Switchgear Room Halon System at the 45-foot elevation. The solenoid's function was to actuate the discharge of Halon from a bank of three of nine Halon cylinders located on the west wall of the room.

Total flooding, Halon 1301 Automatic Fire Suppression Systems, are provided for the 45-foot elevation switchgear room, as well as the 27-foot elevation switchgear room. The Halon storage and distribution system is designed such that in some cases the same banks of bottles supply Halon to either room depending on which room has the fire. There are three banks of bottles; one bank, containing four bottles, only discharges to the 45-foot elevation. A two-bottle bank and a three-bottle bank have selector valves to allow Halon flow to the appropriate room. Therefore, a total of nine bottles would discharge under a fire indication in the 45-foot elevation switchgear room and five bottles would discharge under a fire location in the 27-foot elevation switchgear room. The solenoid for the three-bottle bank was disconnected, which would have prevented this bank from discharging for a fire indication in either switchgear room.

The licensee constituted an investigation team to look into the event. The Team determined that the solenoid was last tagged out of service and returned to service by a Fire and Safety Technician (FAST) on June 29, 1989. The solenoids were taken out of service to allow maintenance technicians to use a torch to heat a motor-generator coupling on the 27-foot switchgear room and to avoid inadvertent actuation of the Halon Systems. The Halon System was disabled by disconnecting each of the three actuation solenoids from its associated Halon cylinder bank. The licensee disables the Halon system utilizing Calvert Cliffs Instruction (CCI) -133, "Calvert Cliffs Fire Protection Plan" as guidance. The inspector has determined that CCI-133 provides no guidance for disabling and restoring to service the Halon System. In addition, there are no procedures in existence that provide instruction for disabling and/or restoring the Halon System. The licensee's inspection team determined that the Halon System for the 45-foot and 27-foot switchgear room had been inoperable between June 29, 1989 and July 20, 1989. This was a violation of the Technical Specification (TS) 3.7.11.3 and the associated Action Statement 3.7.11.30 which requires that the Halon System be operable and that an hourly fire watch be established within one hour of the Halon System being declared inoperable. Additionally, the Action Statement requires that the Halon System be restored to operable status within 14 days or prepare and submit a special report to the Commission pursuant to Specification 6.8.2 within the next 30 days.

The licensee will be reporting this event in an LER. The licensee's failure to recognize the Halon System as inoperable and failure to establish a hourly fire watch within one hour constitutes a violation of the Technical Specifications (50-317/89-18-02).

No other unacceptable conditions were noted.

7.2 Surveillance

The inspector observed parts of tests to assess performance in accordance with approved procedures and LCCs, test results (if completed), removal and restoration of equipment, and deficiency review and resolution.

The following tests were reviewed:

- Surveillance Test Procedure (STP) No. 0-55A-2, Containment Integrity Verification (Mode 6).
- STP No. M-515-1, Primary System RTD Replacement.
- STP No. 0-93-1, Locked Valve Verification Outside Containment.
- STP No. 0-86-1, Boration Flow Path Temperature Determination.
- STP No. 0-8A-1, 11 D/G and 4 kV Buss 11 LOCI Sequencer Test.
- STP No. 0-89-0, Fire Suppression System Weekly Check.
- STP No. M-552-0, Reserve Battery Service Test.
- STP No. 0-60-1, Containment Purge Valve Operability.
- STP No. 0-67-1, Check Valve Operability Verification.

- STP No. M-521-1, ESFAS Response Time Test.

- STP No. O-102-1, Functional Test of Main Vent Gaseous and S/G Blowdown RMS Channels.

- STP M-549-2, Containment Iodine Removal Filter Test (Charcoal).

The inspector had the following comments and observations as a result of reviewing the program area.

-- On April 17, 1989, a Unit 2 steam generator Grinnell T.J. 10"x5" snubber was being reassembled after reconditioning to extend its service life as per Technical Specification 4.7.8.1.e, "Snubber Service Life Monitoring." The snubbers are safety related. The snubbers were manufactured to a Combustion Engineering specification. During the torquing operation, one of the 1" diameter nuts compressing the face plates of the snubber's cylindrical piston/cylinder assembly failed.

  The fractured nut along with nine similar unfractured nuts were sent to the licensee's Material Engineering and Analysis Unit for testing. Original suppliers of the nuts, Tomkins-Johnson, was contacted and indicated that the nut was specified to be "e.t.d." 150 material, which was a proprietary alloy of LaSalle Steel Co. The preliminary results of the analysis were issued on July 10, 1989. The nuts were found to be a resulfurized AISI 1140 grade carbon steel with sulphur ranging between .34-.45 instead of the specified Cr-Mo low alloy steel designated as LaSalle e.t.d., 150 with .06 maximum sulfur and .40 carbon minimum specified. Preliminary testing of the failed nut indicated a wall thickness of 1/8" and a Rockwell hardness of RC-25. This value is equivalent to a tensile strength of approximately 120,000 psi as compared to a minimum specified strength of an e.t.d. 150 nut of 150,000 psi. It is noted that the replacement SA 194-2H nuts as specified by Grinnell are approximately 1/4" thick and contain sulphur to a maximum of .06. The hardness can vary between RC 24-38 with equivalent tensile strengths between 120,000 - 171,000 psi. Although strength and dimensional factors may have been related to the failures, the use of sulfurized steel appears to be the principal cause of failure since high sulfur bearing steel is susceptible to failure when subject to sudden loads, particularly in the vicinity of notches such as the root of threads. The licensee had issued a failure analysis report of the failed nut and has submitted a 10 CFR Part 21 report.

The licensee declared Units 1 and 2 steam generator snubbers inoperable upon receipt of the preliminary analysis results on July 10, 1989. Additionally, the licensee notified the NRC via ENS on the same day.

The licensee has replaced the nuts in all of the steam generator snubbers in Units 1 and 2 (32 snubbers) with SA-194-2H nuts and stated that they will check other Grinnell snubbers for similar material deficiencies. The inspector had no further questions on this issue.

-- On July 13, 1989, with Unit 1 in Cold Shutdown (Mode 5), the licensee's Surveillance Test Coordinator discovered that Surveillance Test Procedure (STP) M-552-0, "Reserve Battery Service Test," was not completed within the time specified (i.e., 18 months plus 25%) by Technical Specifications 4.8.2.3.2. The licensee investigated the event and determined that although the surveillance had not been completed within the specified time interval, the event occurred in Mode 5, whereas Limiting Condition for Operation (LCO) 3.8.2.3 requires the reserve battery to be operable in Modes 1-4. Therefore, the licensee determined that they were not in a mode where the surveillance was required. The surveillance will have to be completed before returning to a mode where the surveillance is applicable. The inspector believes that these circumstances were fortuitous. The licensee continues to lack an effective system which will remedy the apparent weaknesses in the surveillance program and insure surveillances are not missed resulting in plant operation with potentially inoperable equipment.

-- On July 22, 1989, at 2:34 a.m. with Unit 1 in Cold Shutdown (Mode 5), the Reactor Coolant System (RCS) was inadvertently filled from 42.5 feet to approximately 52 feet during the performance of Surveillance Test Procedure (STP) 0-67-1. "Check Valve Operability Verification." This evolution caused some water to enter the pressurizer. Two heaters had been removed from the Unit 1 pressurizer and although there were plugs installed on the two pressurizer sleeves, there was potentially a path for water to spill from the pressurizer. The source of the water was No. 11 Refueling Water Tank which provided borated water at 2540 PPM boron. The licensee had established Safety Tagging No. 19-1014 for Pressurizer Heater Removal to insure pressurizer level was maintained at less than 44 feet which was below the pressurizer surge line penetration to the pressurizer lower head.

Prior to the inadvertent increase of the RCS level, the Control Room Operator (CRO), was performing Low Pressure Safety Injection (LPSI) flow loop checks and adjusting RCS level to maintain approximately 42 feet. RCS level was being increased slowly by using 1-ST-4143-MOV in accordance with Operating Instruction (OI) -03 , "Safety Injection, Shutdown Cooling and Containment Spray." The method used required a waiting period to allow the water in the RCS to equalize and additional filling until the proper level was achieved. The CRO briefed the Auxiliary Building Operator (ABO) on performing Section III.B of STP-0-67-1, "Containment Spray Pump Discharge Check Valves and HPSI Flow Path Check Valves Stroke Test." The aforementioned was to be accomplished after the desired RCS level was attained. While the CRO was still in the process of securing the valve line-up for the RCS fill, he directed the ABO to perform steps III.B.3, 5 and 6 of STO 0-67-1. The CRO did not perform step III.B.4 (Shut SI-432, #12 LPSI Pump Normal Suction Isolation Valve). When SI-432 was open and with SI-4143-MOV open, a direct flow path existed from the RWT to the suction of the running #11 LPSI pump. The CRO was monitoring RCS level and noticed the increasing level. The CRO notified the Control Room Supervisor who recognized that 1-SI-4143-MOV was open. The CRS directed the CRO to shut 1-SI-4143-MOV and stop the ABO from opening 1-SI-432. The entire evolution occurred in a relatively short period of time. Most of the increase in level resulted from the time required for the MOV to close. Using OI-03 Section III, the CRO drained the RCS to No. 11 RWT and re-established a level of less than 44 feet.

The licensee identified several weaknesses associated with this event:

(1) Step 5 of STPO-67-1 was performed prior to the completion of step 4. Clearly a procedure compliance problem.

(2) The CRO was performing two tasks at the same time (i.e., OI-03 maintaining RCS level and STP 0-67-1). This tended to divide the CRO's attention between the two tasks and increase the risk of error.

The licensee is considering the following corrective actions:

(1) Steps in procedures must be performed and completed in sequence unless specified otherwise.

(2) Steps in a procedure are not considered complete until they are signed off.

(3) Assign individual to perform STPs and make them responsible to ensure steps are signed off prior to continuing.

(4) Dedicate full attention to the accomplishment of STPs.

Technical Specification 6.8.1 stated that written procedures shall be implemented covering the applicable procedures recommended in Appendix A of Regulatory Guide 1.33, Revision 2. Appendix A of Regulatory Guide 1.33, Revision 2, requires procedures for implementation of Technical Specification Surveillances.

STPO-67-1 requires that step 4 which closes 1-SI-4143-MOV be performed prior to opening SI-432 per Step 5. The licensee failed to follow the steps in the procedure in their proper sequence. This constitutes another example of failure to follow procedures which has been the subject of recent escalated enforcement actions. The licensee has made restart commitments to improve procedural adherence before restart as addressed in Confirmatory Action Letter 89-08, dated May 25, 1989.

This is a licensee identified violation in accordance with 10 CFR 2, Appendix C, Section V.G (50-317/89-18-01).

-- On July 31, 1989, with Unit 1 in Cold Shutdown (Mode 5), licensee Surveillance Test Program personnel discovered a failure to comply with Technical Specification Surveillance 4.9.12.a. The surveillance requirement states in part, "At least once per 31 days ... verifying that each charcoal absorber bank and each exhaust fan operates for at least 15 minutes." Surveillance Test Procedure (STO) 0-7-1, "Engineered Safety Features Monthly Logic Test" has detailed steps ensuring that the charcoal filters are run for the required time, however, the STP does not call for testing the fans. The testing of the filters requires that at least one spent fuel exhaust fan be in service. The filter run time is logged in the charcoal filter log bank. There are no requirements procedural or otherwise requiring the logging of the spent fuel exhaust fan in service or the amount of running time. The licensee has reviewed the history of STP 0-7-1 and found that the testing of the filters was added in 1978. A search of subsequent procedure reviews indicates that the requirement to test the exhaust fans was not recognized. It is reasonable to assume that this requirement has never been met.

The STP program is currently being reorganized and revised. Under the old program, biennial reviews were arranged by the STP coordinator. The reviews were stipulated to verify that procedures were correct and satisfied the requirements of the Technical Specifications (TS). The last review performed on STP 0-7-1 was in December 1988. The last previous Quality Assurance (QA) Audit on TS surveillance requirement 4.9.12.a was in 1985. Apparently, neither biennial reviews nor QA audits discovered the failure to satisfy the TS surveillance requirement. Upon discovery of the event, the licensee swapped fans to ensure that the surveillance requirements were met as soon as possible. Further, the licensee has identified the following corrective actions to be fully implemented as soon as practical:

1. The steps for testing the spent fuel charcoal filters have been removed from STP-0-7-1. A new STP incorporating steps to run the filters and the fans has been issued.

2. A detailed review of all procedures used to satisfy Technical Specification Surveillance requirements is currently in progress. The review will ensure each surveillance is fully covered by a procedure.

3. The STP program is being upgraded. The program will assign Functional Surveillance Test Coordinators (FSTC) responsibility for overseeing and maintaining the Surveillance Test Procedures assigned to them. The FSTC will ensure that Technical Specification Surveillance requirements are addressed by those procedures. All new Surveillance Test Procedures will be generated and reviewed using strict guidelines designed to ensure surveillance compliance. New procedure reviews and biennial reviews of each STP will consist of two parts. The first part will be a technical review by a System/Component Engineer. The second part will be a functional review by the department responsible for performing the procedure.

4. The QA Technical Specification audit process has been improved. The audit process has become more technically oriented and the audit checklist has been expanded.

Failure to perform required surveillance testing in accordance with Technical Specification Surveillance requirement 4.9.12.a is a violation (317/89-18-03).

The inspector will follow any further corrective action by the licensee during routine inspection followup.

8. Engineering Support

8.1 Unit 1 Saltwater Header Not Seismically Qualified

On or about March 2, 1989, the licensee was performing a walkdown of the saltwater piping for an unrelated design effort when they discovered that a 16 inch pipe section of pipe whose stress analysis had been credited with being capable of transmitting loads, was tack welded. The tack welds were immediately replaced with continuous welds and a recent analysis shows that the piping will remain intact during a seismic event. The licensee had an analysis performed to determine the effect of only having tack welds during a potential seismic event. The analysis indicated that the #12 saltwater header would fail. Back flow resulting from the failure would render the #12 saltwater header useless. The header supplies cooling water to the component cooling and service water systems.

The 16 inch section of pipe was a modification which was made during initial construction. The licensee has been unable to determine whether the tack welding was original design or personnel error. The investigation continues on the saltwater, component cooling and service water system to determine whether additional spools are correctly welded.

The licensee determined on July 23, 1989, that the #12 saltwater header would not have been capable of withstanding a seismic event in its previous tack welded condition. This issue represents an example of the licensee's effort to proactively identify and resolve problems. The inspector will continue to monitor the licensee's efforts in these areas. The licensee notified the NRC via the ENS on August 15, 1989, and submitted a voluntary LER on this issue.

8.2 Iodine Filter Dousing System

As part of a project to resolve environmental qualification (EQ) issues identified for the containment iodine filters, the licensee reviewed the iodine filter dousing system and discovered that the system was not covered under the 10 CFR 50.49 program. Repeated reviews of the system eventually led the licensee to determine that the function of the dousing system was safety related. Its function was characterized as preventing re-release of collected iodine in the event of a fire. The licensee discovered that the original calculation contained several flaws and ordered a new calculation to address their concerns. The calculation was completed in May 1989. The EQ technicians evaluation was completed and determined, on August 22, 1989, based on the new calculation, that the dousing system is required to prevent the re-release of iodine trapped by the containment iodine filter. As a result of the determination, the dousing system components have been added to the 10 CFR 50.49 list and the Q-list. Unit 1 was in Cold Shutdown (Mode 5) and Unit 2 was defueled at this time. The licensee notified the NRC via the ENS and will be describing this issue in an LER. The licensee will prepare a report once the off-site dose calculation becomes available which will address the safety significance of the event. Prior to restarting either unit, the licensee will be preparing a Justification for Continued Operation (JCO) which will address the issue of continued operation until an evaluation can be made to determine the permanent solution.

The issue of operability of the dousing system remains unresolved pending the licensee resolution of outstanding items (50-317/89-18-04; 50-318/89-19-01).

9. Licensee Event Reports (LERs)

LERs submitted to NRC:RI were reviewed to verify that the details were clearly reported, including accuracy of the description of cause and adequacy of corrective action. The inspector determined whether further information was required from the licensee, whether generic implications were indicated, and whether the event warranted on site follow up. The following LERs were reviewed:

9.1 Unit 1

LER No.	Event Date	Report Date	Subject
89-009	05/19/89	07/07/89	Inadequate Procedure for Providing Alternate Shutdown Capability as Required by Appendix R
89-010	06/14/89	07/14/89	Equipment Qualification Problem in 5' East Piping Penetration Room Due to HELB Environment
89-011	06/30/89	07/31/89	Missing Fire Protection Damper

LER No.	Event Date	Report Date	Subject
Unit 1 (Continued)			
89-012*	07/20/89	08/21/89	Discovery of a Disconnected Actuator Solenoid Partially Disabling the Halon System for the 27-foot and 45-foot Switchgear Rooms
Unit 2			
89-009	05/22/89	07/21/89	Closed Fire Damper Penetration Ventilation Exhaust System
89-010	06/23/89	06/23/89	Missed Fire Protection Surveillance
89-011*	07/10/89	08/10/89	Fractured Nut Caused by Inadequate Dimensional Properties Results in Inoperable Steam Generator Snubbers

*Detailed examination of these events is documented in Sections 7 and 8 of this inspection report.

No unacceptable conditions were identified.

10. Review of Periodic and Special Reports

-- June 1989, Operating Data Reports for Calvert Cliffs Units No. 1 and 2, dated July 14, 1989.

-- July 1989, Operating Data Reports for Calvert Cliffs Units No. 1 and 2, dated August 10, 1989.

-- 1989 Nuclear Program Quarterly Performance Report - 2nd Quarter 1989, dated August 10, 1989.

No unacceptable conditions were identified.

11. Events Requiring Telephone Notification to the NRC

The circumstances surrounding the following events requiring prompt NRC notification pursuant to 10 CFR 50.72 were reviewed.

-- At 10:28 a.m., on July 10, 1989, the NRC was notified in accordance with 10 CFR 50.72(a)(2)(ii)(B), that the licensee had determined that the Unit Nos. 1 and 2 Nos. 11, 12, 21 and 22 steam generator snubbers (8 per steam generator) were inoperable due to improper assembly nut material. The nuts hold the piston/cylinder assembly of the steam generator snubbers intact. The licensee issued LER 50-318/89-011 to document this event along with notification and written report in accordance with 10 CFR 21 which was reviewed by the NRC as part of followup activities. This event is discussed further in Section 7.2 of this report.

-- At 9:35 a.m., on July 20, 1989, the NRC was notified in accordance with 10 CFR 50.72(b)(2)(i), that the licensee had found the Unit 1 Halon System for the 45 foot and 27 foot Switchgear Rooms partially defeated. During the performance of a Surveillance Test, a 3 bottle Halon bank that feeds the 45 foot and 27 foot switchgear rooms was found to have its actuation solenoid unplugged. In the event of a required actuation from either room, the resulting Halon concentration would have been less than the designed. The licensee plans on issuing LER 50-317/89-012 to document this event and it will be reviewed by the NRC as part of LER followup activities. This event is discussed further in Section 7.2 of this report.

-- At 6:25 a.m., on August 15, 1989, the NRC was notified in accordance with 10 CFR 50.72(b)(2)(i), that the licensee had determined that the Unit 1 No. 12 Salt Water header would have been overstressed during a seismic event. Failure of the No. 12 Salt Water header would have rendered No. 12 Service Water heat exchanger and the No. 12 Component Cooling Water heat exchanger inoperable. This issue is discussed further in Section 8 of this report.

-- At 6:18 p.m., on August 17, 1989, the NRC was notified in accordance with 10 CFR 50.72(b)(2)(i), that the licensee had determined that Units 1 and 2 Chemical and Volume Control System make-up mode selector switch HS-210 did not meet FSAR design requirements. The separation requirement did not exist in the hand switch.

-- At 6:16 a.m., on August 19, 1989, the NRC was notified in accordance with 10 CFR 50.72(b)(2)(vi), that the licensee discovered an oil spill of approximately 15 gallons in Unit 1 Main Turbine Lube Oil Reservoir Purifier area due to a lost water seal Rags were used to contain and clean up the oil. The National Response Center was notified of this event.

-- At 5:18 p.m., on August 22, 1989, the NRC was notified in accordance with 10 CFR 50.72(b)(2)(i), that the licensee had discovered that the do ing system for Units 1 and 2 containment iodine filters is not environmentally qualified. The licensee plans on issuing an LER to document this event and it will be reviewed by the NRC as part of LER followup activities. This event is discussed further in Section 8 of this report

No unacceptable conditions were noted.

12. Management Meetings (30703)

Meetings were periodically held with senior facility management to discuss the inspection scope and findings. A summary of findings was presented to the licensee at the end of the inspection.