U.S. NUCLEAR REGULATORY COMMISSION
REGION I

Report Nos. 50-317/95-06; 50-318/95-06

License Nos. DPR-53/DPR-69

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

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

Location: Lusby, Maryland

Inspection conducted: June 25, 1995, through August 5, 1995

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<u>Inspection Summary</u>:

Core, regional initiative, and reactive inspections performed by the resident inspectors during plant activities are documented in the areas of plant operations, maintenance, engineering, and plant support. Additionally, inspections conducted by regional inspectors are documented in the areas of radiological controls and nondestructive examination.

<u>Results</u>:

See Executive Summary.

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EXECUTIVE SUMMARY

Calvert Cliffs Nuclear Power Plant, Units 1 and 2

Inspection Report Nos. 50-317/95-06 and 50-318/95-06

<u>Plant Operations</u>: BGE response to a faulty control element assembly position indicator on Unit 2 was complicated by a failure in a main turbine governor valve control card. The faulty position indicator was caused by a loose electrical connector in containment. Interdepartmental coordination was excellent while resolving the equipment problems. The pre-evolution briefing prior to the turbine shutdown was a significant contributor to preventing an inadvertent trip. The inspectors noted excellent shift supervision with good attention to reactivity management as the turbine was removed from the grid.

BGE management was conservative in their decisions regarding reduced power operation on Unit 1 during a period when service water system operability was threatened by high Chesapeake Bay temperatures. The functional evaluations used to support continued plant operation were very good, clearly written and used reasonable assumptions.

<u>Maintenance</u>: A violation was identified involving the lack of foreign material exclusion controls during maintenance on the station blackout diesel generator. Foreign material exclusion control has been a recurring problem, indicating that previous corrective actions have not been effective.

<u>Engineering</u>: A violation was identified regarding the control of plant drawings. More than 1000 drawings (1 to 2% of the critical or Category 1 drawings) at various plant locations, including the control room, were not of the correct revision. A root cause for this issue was inadequate supervisory oversight.

Inadequate communication of information regarding equipment operability resulted in a slow BGE response to some degraded plant components, specifically, a saltwater discharge valve on the 22 component cooling water heat exchanger and fire barriers in expansion joints. In addition, there continues to be an insensitivity to statistical significance.

<u>Plant Support</u>: Effective occupational exposure controls were implemented during the Unit 2 refueling outage. There were no unplanned external or internal exposures. Areas for improvement were identified in the program for identification, documentation, and follow-up of personnel contaminations.

The training certifications for all of the fire and safety technicians performing surveillance testing had expired. This was a violation. The safety concern was minimal as the completed surveillances were reviewed by a qualified reviewer and there were no indications of improper performance. The issue highlighted significant weaknesses in documentation of qualification and recertification due to a longstanding lack of supervisory oversight.

(EXECUTIVE SUMMARY CONTINUED)

Safety Assessment/Quality Verification:

The inspectors noted excellent supervisory oversight of the two major challenges to plant operations this period, caused by some equipment problems that affected Unit 2, and high bay water temperatures that affected both units. BGE demonstrated good judgement, excellent plant control, and strong safety perspective in resolving both challenges.

The good performance exhibited in resolving the two major challenges was contrasted, however, by apparent failures in supervisory oversight of more routine, less dynamic responsibilities regarding control of plant drawings, qualification of personnel to perform fire system surveillance testing, and foreign material exclusion control. Inspectors assessed that the contrast indicated that BGE continued to exhibit good management of emergent, high visibility issues, while they continued to be less successful in meeting management expectations and resolving longstanding deficiencies in some lower visibility programs.

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DETAILS

1.0 SUMMARY OF FACILITY ACTIVITIES

Unit 1 began the period at full power. On July 31, rising temperatures in the Chesapeake Bay forced BGE to declare the service water system inoperable and to commence a unit shutdown. BGE reduced power to 55% before bay temperature cooled low enough to restore the service water system to operability and stop the unit shutdown. On August 2, BGE raised power to 80%. On August 4, as bay temperatures remained below the limit, BGE raised power to 100%. BGE's difficulties with and responses to the high bay water temperatures are discussed below.

Unit 2 began the period at full power. On July 24, BGE reduced power to approximately 8% and took the main generator off the grid to repair a faulty position indication on control element assembly #8 and to replace a faulty control card for main turbine governor valve #2. The evolution is discussed below. The unit returned to full power on July 25.

2.0 PLANT OPERATIONS (INSPECTION PROCEDURES (IPs) 71707, 92901)[1]

The inspectors observed plant operation and verified that the facility was operated safely and in accordance with licensee procedures and regulatory requirements. This review included tours of the accessible areas of the facility, verification of engineered safeguards features (ESF) system operability, verification of proper control room and shift staffing, verification the units were operated in conformance with technical specifications and that appropriate action statements for out-of-service equipment were implemented, and verification that logs and records were accurate and identified equipment status or deficiencies. During the inspection period, the inspectors also provided onsite coverage and follow-up of unplanned events.

2.1 Follow-up of Events Occurring During the Inspection Period

a. Unit 2 Faulty CEA Position Indication

On July 22, BGE discovered a problem with the secondary position indication on Unit 2 control element assembly (CEA) #8 due to a loose cable connection in containment. When selected, the secondary position indicator for CEA #8 would indicate inward movement with no actual rod motion, as verified by the primary position indication and nuclear instruments. BGE also discovered that when the rod bank was pulled out to energize the "full out" electrical limit switches, the indicator for CEA #8 displayed intermittent contact. Its "full out" indicating light would flicker, staying on for periods from 15 seconds to 5 minutes, and then go out. Moving the CEA would light the indicator again. The primary pulse counting position indication system operated properly, but technical specifications required at least two of the three CEA position indicator channels to be operable.

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[1] The NRC inspection manual procedure or temporary instruction that was used as inspection guidance is listed for each applicable report section.

Investigation and troubleshooting indicated a loose connection inside containment was causing both the faulty secondary position indication and the intermittent "full out" indication. In order to reduce radiation levels and allow access to the reactor vessel head to repair the connector, BGE decided to take Unit 2 off line. As they began reducing the main turbine load on July 24, however, they discovered that governor valve #2 (GV-2) was stuck at 90% open. Following troubleshooting and consultation with the turbine manufacturer, BGE used the governor valve test circuit to shut the valve. As a result of the faulty control card, GV-2 did not operate as expected and the unit lost 130 MWe when the valve went quickly shut. Operators were aware of the potential of a load rejection as they shut GV-2, and maintained good control of the plant. They then hydraulically isolated GV-2 and continued the turbine shutdown. During the shutdown, a problem in the control circuit of the operating steam generator feed pump (SGFP) caused the pump to slow down to minimum speed. The standby pump was immediately placed in service and operated properly.

BGE kept Unit 2 in Mode 1 at 6-10% power while conducting repairs to CEA #8 position indication and to GV-2. BGE found the problem on CEA #8 was a loose connector. The connector was tightened and lock-wired and tested satisfactorily. No other loose connectors were found. BGE determined the problem on GV-2 was a faulty AW-3 control card. It was replaced and the valve was tested satisfactorily. The card was sent to the manufacturer to determine the cause of the failure. The problem in the control circuit of the SGFP was a dead spot on a potentiometer. The potentiometer was replaced and tested satisfactorily, and the other SGFP potentiometer was verified to be operating properly. Following post maintenance testing, BGE returned the unit to service.

Inspectors closely monitored BGE corrective actions and the turbine shutdown on Unit 2. Good coordination was noted between operations, maintenance, engineering, and radiation safety staff in safely resolving the equipment problems. The functional evaluations/operability determinations of the CEA position indication system and the CEA motion inhibit circuit were technically sound. BGE demonstrated a good safety perspective in deciding to take the unit off line to repair the CEA indication problem rather than try to work around it. The failure of GV-2 presented several challenges to operators in safely removing the unit from service without causing a trip. Inspectors noted excellent shift supervision with good attention to reactivity management. The pre-evolution briefing before closing GV-2 was thorough, and the discussion of potential scenarios helped to ensure that operators were well prepared for the load rejection transient when GV-2 shut faster than expected. The post evolution critique noted that adjusting the turbine bypass valves to be more responsive to the potential transient, and operating the standby SGFP at just below running pump speed for quicker response, were significant contributors to preventing an inadvertent trip. Inspectors assessed that BGE's safety perspective and operator control of the unit while resolving the equipment problems were excellent.

b. Technical Specification Required Shutdown Due to High Chesapeake Bay Temperature

On July 31 Unit 1 entered Technical Specification (TS) 3.0.3 when both service water heat exchangers (SRWHXs) were declared inoperable due to high circulating water inlet temperature. Operators began reducing power in compliance with the TS and later exited the TS at 5:55 p.m. when 12 SRWHX was declared operable after its cooling water inlet temperature dropped below 87°F. Reactor power was stabilized at 55%. No. 11 SRWHX was cleaned and returned to service on August 1. Power was increased to 80% on August 2 and to 100% on August 4. Throughout the course of resolving the temperature related issues, BGE maintained a strong safety perspective related to reduced reactor power operation, and the engineering evaluations supporting operation at several different power levels were clearly written and used reasonable assumptions.

At Calvert Cliffs, the service water (SRW) system provides cooling water to a number of safety-related and non-safety-related systems and components. The two service water heat exchangers are, in turn, cooled by the saltwater (SW) system which takes its suction from the Chesapeake Bay. The saltwater pumps are located in the intake structure, with the Unit 1 pumps at the north end and the Unit 2 pumps at the south. The circulating water from the main condensers share a common discharge path with the outfall located in the Chesapeake Bay north of the intake structure. A baffle wall surrounds the plant's waterfront area and provides a physical barrier to upper strata water, debris, and sea life.

In order to be considered operable, each heat exchanger must meet the differential pressure and condenser inlet temperature criteria graphed on Figure 4 of Operating Instruction (OI)-29. On July 31, operators observed a substantial increase in the Chesapeake Bay water temperature at the inlet of the circulating water pumps. Shortly after noon, the temperature exceeded the maximum permissible of 87.0°F. Operators declared both SRWHXs inoperable, made the appropriate notifications to the NRC and commenced a unit shutdown. The temperature peaked at 88.1°F for Unit 1 and 86.9°F for Unit 2. Operators terminated the shutdown when inlet temperature trended down below 87.0°F; reactor power was about 55% at that time. Given the expectation that the sustained hot weather would continue for some time, BGE management elected to operate Unit 1 at reduced power until an engineering analysis (functional evaluation) could demonstrate that higher inlet temperatures were acceptable and remained bounded by the accident analyses in the Updated Final Safety Analysis Report (UFSAR). BGE also initiated an investigation of the cause for the elevated temperature and possible solutions. A root cause analysis of the entire event was in progress when the inspection period ended.

The first functional evaluation (July 31) supported a temperature of 87.4°F at 100% power. BGE management did not regar this as adequate given the actual temperature reached that day. A second evaluation (August 1), using actual plant operating parameters, supported 87.7°F at 100% power. A third evaluation (August 2), using a lower power level (and hence lower decay heat loads), supported a limit of 89.0°F at no more than 80% power. Based on these results, Unit 1 power was increased to 80% on August 2.

BGE's investigation indicated that the elevated temperatures were probably due to a combination of tide and wind effects on the circulating water discharge plume and the baffle wall configuration. Several panels in the northern end of the wall had been removed to facilitate fish egress. Under certain conditions, some of the discharge water could be pushed into the intake area through the openings in the wall and entrained in the [illegible] water inlet water, elevating its temperature. Unit 1 appeared more susceptible to this because of its pumps' location compared to Unit 2's. Historically, Unit 2's inlet temperature had run 1-1.5°F cooler than Unit 1. On August 3, BGE reinstalled the two northernmost baffle panels. Although weather conditions were similar to those earlier in the week, Unit 1's inlet temperature did not exceed 85.2°F and reactor power was increased to 100% on August 4.

The inspectors discussed the issues surrounding the elevated inlet temperatures with BGE management, engineering and operations personnel and closely monitored BGE's efforts to reduce the temperature while maintaining power operation. The inspectors also reviewed the various functional evaluations performed to support plant operation. Overall, the inspectors concluded that BGE management was conservative in their decisions regarding reduced power operations with due regard for reactor safety and technical specification philosophy. The functional evaluations were clear, used reasonable assumptions, and supported plant operation within the parameters assumed in the analyses. The twice daily meetings between the various groups involved in resolving the issues were well managed and allowed a free and open discussion of the safety consequences of proposed solutions.

2.2 Plant Operations and Safety Review Committee

The inspectors attended several Plant Operations and Safety Review Committee (POSRC) meetings. TS 6.5.1 requirements for required member attendance were verified. The meeting agendas included safety significant issue reports, proposed tests that affected nuclear safety, 10 CFR 50.59 evaluations, reportable events, and proposed changes to plant equipment that affected nuclear safety. The POSRC demonstrated a strong questioning attitude during their June 28 meeting. See section 4.2 for details.

3.0 MAINTENANCE (IPs 62703, 61726, 92902)

3.1 Routine Maintenance Observation

The inspector reviewed selected maintenance activities to assure that the work was performed safely and in accordance with proper procedures. Inspectors noted, with one exception discussed in section 3.4, that an appropriate level of supervisory attention was given to the work depending on its priority and difficulty. Maintenance activities reviewed are listed in Attachment 1.

3.2 Routine Surveillance Observation

The inspectors witnessed/reviewed selected surveillance tests to determine whether properly approved procedures were in use, details were adequate, test instrumentation was properly calibrated and used, technical specifications were satisfied, testing was performed by qualified personnel, and test results satisfied acceptance criteria or were properly dispositioned.

The surveillance testing was performed safely and in accordance with proper procedures. Inspectors noted that an appropriate level of supervisory attention was given to the testing depending on its sensitivity and difficulty. Surveillance testing activities reviewed are listed in Attachment 1.

3.3 Ultrasonic Coverage

Unresolved Item 50-318/95-03-01 was identified during the Non-Destructive Examination (NDE) Mobile Laboratory inspection at Calvert Cliffs, April 4 through April 14, 1995. The report for this inspection identified a concern with the ultrasonic coverage of the required weld inspection volume (RWV), as described in the ASME Code, Section XI, IWB-2500-8.

The NRC performed an inspection on June 26, 1995 to evaluate the corrective actions for this unresolved item. During the exit of the NDE Mobile Laboratory inspection on April 14, 1995, BGE acknowledged the concern and agreed to determine the extent of the problem and identify the necessary short and long term corrective actions.

BGE determined that the root cause of inadequate coverage of the RWV was transducer wedge lift off. Lift off can occur in the area of weld toes and nonparallel surfaces, such as the weld crown. Lift off is the uncoupling of the ultrasonic transducer from the inspection component. Ultrasonic sound cannot penetrate through air, therefore, sound transmission into the component is interrupted when the transducer is uncoupled.

As immediate corrective action, BGE reviewed seventy-three (73) ISI welds inspected during the current Unit 2 outage and pre-outage. The review was limited to those pipe welds that have a RWV. BGE reviewed the inspection packages in order to determine if there was a potential concern for a lack of coverage in the RWV. They identified welds with a geometric configuration conducive to a lift off problem and subjected these welds to further review and evaluation.

BGE identified four welds as potential lift off problems and thirteen other welds with contours conducive to lift off. Two of these welds were the welds originally identified by the NRC. The other welds were reexamined by BGE's ultrasonic (UT) Level III. Coverage of the RWV was found to be acceptable in both of the welds reexamined by BGE, 30-RC-22A-9 and 30-RC-22A-10.

The NRC reviewed selected inspection packages identified as suspect by BGE. The weld numbers of the packages inspected were: 6-SI-2204-15; 6-SI-2004A-12; 12-SC-2015-16; and 4-PS-2003-3. Coverage of the RWV was satisfactory in all four of the inspection packages chosen. The NRC inspectors agreed with BGE's conclusion as to the acceptability of RWV coverage.

BGE Issue Report IRO-055-107 documented the original concern with RWV as well as other long term corrective actions. Corrective actions included the use of scan plans, improved training of the personnel performing and evaluating the examinations, and evaluating the use of alternate inspection techniques. Scan plans were intended to identify the potential for lift off, investigate different angles of inspection and scanning techniques. The training was to bring awareness of potential problems to the examiners and data reviewers. BGE was investigating the use of alternate scanning angles to eliminate some geometric configuration restrictions which could reduce the RWV coverage. The intended completion of the investigation was October 1995.

BGE intended to have the corrective actions in place for the upcoming Unit 1 outage, March 1996, and has implemented some of the corrective actions in Administrative Procedure MN-3-312, Revision 1, "Inservice Inspection Plans and Summary Report." BGE's assessment of the corrective actions will not be complete until June 1996. The unresolved item is closed, based on the actions taken and planned by BGE.

3.4 Foreign Material Exclusion Deficiencies During Maintenance

On July 13, during an observation of maintenance activities on the new station blackout (SBO) diesel generator and support equipment, the inspectors observed that elements of the diesel engine were exposed for maintenance without protection to preclude the introduction of foreign material. When informed of this observation, BGE took prompt corrective action. However, the inspectors concluded that this event represented another lapse in the implementation of BGE's foreign materials exclusion (FME) program and indicated that BGE's past corrective actions have not been fully successful.

As described in maintenance order (MO) 5199500161, the SBO diesel generator was out of service undergoing its scheduled 2-year overhaul. The MO specified the use of diesel generator project (DGP) procedure DGP-SU-008 to maintain system cleanliness. Elements of the diesel engine, including the fuel oil injection pump and piston valve covers, had been earlier disassembled or opened for inspection and maintenance. At the time of the inspectors' observation, night shift personnel had ceased work and left the work area. The inspectors noted that while material loosely covered some of the work area, no foreign material controls, as detailed in Attachment 7 of DGP-SU-008, appeared to be in effect. The inspectors brought the issue to BGE maintenance management's attention, who promptly initiated an investigation and took action to establish the necessary FME controls. BGE's corrective actions included a visual examination of the affected areas to verify that no foreign material had been introduced, counseling of the personnel involved, and a review of the event with all maintenance personnel.

The inspectors discussed the results of the investigation with BGE management and noted the following:

- DGP-SU-008 was a procedure which established system cleanliness requirements for pre-turnover construction activities. FME controls described in section 5.6 and Attachment 7 were intended to address construction, not maintenance activities. DGP-SU-008 was neither as detailed nor as rigorous as the plant procedure for the control of foreign material, MN-1-109.

- MO 5199500161 specified the use of DGP-SU-008 for all maintenance work. However, the MO checklist detailing the cleaning of the air intake filters required the use of MN-1-109. The understanding of the maintenance planning supervisor was that only DGP procedures would be used. The maintenance personnel thought that they could ignore the quirements of MN-1-109 because the work was under the scope of DGP-SU-008.

- Some maintenance personnel preferred the use of DGP-SU-008 to MN-1-109 because it was less prescriptive and contained fewer administrative requirements.

- MN-1-109 had been extensively revised due to longstanding problems with FME controls and all maintenance personnel had received training on the revised procedure, as well as tailgate sessions to reiterate management's expectations regarding FME and to increase site wide awareness of the issue.

- Maintenance supervisory and craft personnel for the SBO diesel work did not note the apparent lack of FME controls at the job site, nor assure that requirements regarding system cleanliness, as stated in the MO, were met.

The inspectors noted that the safety significance of the issue was minimal as the SBO diesel was still in a construction status and not required to fulfill a safety or emergency function. BGE did not find that any foreign material had been introduced into the SBO diesel.

The inspectors concluded that a number of factors contributed to this event, including:

- Procedure noncompliance. Personnel performing the maintenance activity did not adhere to the requirements of DGP-SU-008, MN-1-109 or the MO.

- Lack of a questioning attitude. Lack of specific FME controls and conflicting procedural requirements were not questioned by either craft or supervisory personnel.

- BGE management's expectations regarding FME and procedural adherence were well known by all site personnel. However, supervisory oversight was not adequate to ensure these expectations were met.

- Ineffective corrective actions. Longstanding programmatic deficiencies had not been adequately addressed to prevent recurrence, despite several previous violations and inspector observations.

Despite BGE's prompt corrective actions following notification of the inspectors' observation, the inspectors noted that, overall, BGE's continuing efforts to correct foreign material exclusion issues were still not successful. 10 CFR 50, Appendix B, Criterion XVI, requires that issues adverse to quality be promptly identified, corrected, and actions taken to preclude repetition. Therefore, BGE's failure to effectively correct the FME issues was a Violation of NRC requirements (VIO 95-06-01).

4.0 ENGINEERING (IPs 92903, 37551)

4.1 Problems with the Control of Plant Drawings

In NRC Inspection Report 50-317 and 318/95-05, the NRC documented that some controlled plant drawings located in the control room and in the plant were not of the correct revision. This problem was considered unresolved (URI 95-05-01) at the conclusion of the above inspection. As a result of the drawing control problems identified in the control room, BGE initiated a 100 percent drawing verification audit of all site locations that contained controlled drawings. Similar problems were identified at most drawing locations. The results of BGE's audit are documented below.

When performing their audit, BGE categorized drawing locations as critical areas and other hard copy areas. Critical area locations included the control room, safety tagging office and the print room in the South Services Building. When taking into account drawing revisions in routine transit, BGE found that approximately 1 percent of the controlled drawings in the critical areas outside the control room were not of the correct revision. The other hard copy areas included the Motor Operated Valve Project office, the Operations Support Center, the Technical Support Center and the design engineering drawing location. In these areas, BGE found approximately 2 percent of the controlled drawings were not of the correct revision. BGE corrected all of the incorrect drawings. BGE elected not to evaluate the safety significance of the drawing errors based on a previously performed evaluation (discussed in section 4.2 of Inspection Report Nos. 50-317/95-05 and 318/95-05) regarding control room drawings that indicated there were not any significant safety concerns. As discussed in Inspection Report 95-05, the errors were minor in nature and did not adversely affect safe operation of the units. Examples included incorrect piping line and valve numbers due to modifications.

The inspectors concluded that the root cause of the drawing problems was inadequate supervisory oversight. The use of transmittal tracking forms was discontinued in late 1994. Drawing audits were not performed using accurate distribution lists and the audits were not always thorough. A contributing cause was the inconsistent use of check out cards by plant personnel.

10 CFR 50, Appendix B, Criterion VI, requires, in part, that "measures be established to control the issuance of documents, such as instructions, procedures, and drawings, including changes thereto, which prescribe all activities affecting quality. These measures shall assure that documents, including changes, are reviewed for adequacy and approved for release by authorized personnel and are distributed to and used at the location where the prescribed activity is performed." Therefore, the failure to maintain the

correct revisions of controlled drawings at various site locations is a Violation of NRC requirements (VIO 95-06-02). Unresolved Item 95-05-01 is administratively closed.

4.2 Functional Evaluations Not Aggressively Pursued

On two occasions, BGE did not promptly recognize the need to perform functional evaluations following the discovery of degraded plant components. The first involved a safety-related valve and the second a degraded wall expansion joint. BGE uses functional evaluations to assist in the determination of operability for degraded components. A common contributing cause for these problems was inadequate communications. The inspectors reviewed both problems and documented their findings below.

Following the NRC's issuance of NRC Generic Letter 91-18, BGE developed and implemented site administrative procedure NO-1-106, "Functional Evaluations/Operability Determinations." The purpose of this procedure was to provide the process for addressing an operability issue which existed because the full qualification status of the nonconforming or degraded installed structures, systems, or components (SSC) could not be unequivocally demonstrated. NO-1-106 provided a formal process to determine operability of a degraded SSC when the operability of the SSC was unclear. When the operability of a SSC was not readily ascertained, NO-1-106 required operators to obtain a functional evaluation of the degraded SSC from the system engineering organization. This documented functional evaluation provided the engineering basis for operability. Operations staff maintained a copy of all functional evaluations in the control room.

a. Degraded Safety-Related Valve

On June 1, 1995, during a surveillance test, the saltwater discharge valve (2-SW-5208-CV) to 22 component cooling water heat exchanger failed to stroke fully open. This valve is required to close during the injection phase of a postulated loss of coolant accident and is then required to open to a preset position during the recirculation phase of the accident. Unit 2 Technical Specification (TS) 3.7.5.1 required that two independent saltwater loops be operable. The TS allowed for 72 hours of continued plant operation with one inoperable loop.

The valve stopped opening at the 60% open position. During troubleshooting efforts, the operators attempted to stroke the valve open seven additional times and each time the valve stopped at the 60% open position. The troubleshooting did not identify the cause of the problem. The control room operators did not declare the valve inoperable during this period (approximately two hours). During the next attempt to stroke open the valve, it fully opened within the stroke time criteria specified in the surveillance test. Operators then successfully stroked the valve open two additional times and the surveillance test was completed satisfactorily.

During this troubleshooting period, the operators performed a saltwater flow verification test according to Operating Instruction (OI)- 29 "Saltwater System." This test determined the flow available to the component cooling water heat exchanger by measuring a pressure decrease across the service water heat exchanger with flow isolated to the component cooling water heat exchanger. The test indicated there was sufficient saltwater flow to the 22 component cooling heat exchanger with 2-SW-5208-CV only 60% open.

Operations staff generated an issue report to document the valve's failure to fully open. In addition, they generated a maintenance order to investigate and repair the valve malfunction. The issue report was screened by the Issues Assessment Unit (IAU) and classified as "hardware only."

On June 9, the responsible system engineers decided to stroke test the valve more frequently (every two weeks versus every month) vice performing additional troubleshooting. They directed that the maintenance order be force closed (i.e., closed with no action taken). The engineers believed that the troubleshooting performed on June 1 was exhaustive and that further troubleshooting would not reveal the cause of the problem because the valve was stroking open properly. Operators were not informed that the maintenance order had been force closed.

On June 21, a Functional Surveillance Test Coordinator (FSTC) reviewing the completed surveillance test identified that operators had not declared 2-SW-5208-CV inoperable when the valve could not be stroked fully open as required by the surveillance test. He also found that the maintenance order was inappropriately closed and had been misclassified as a "hardware only" problem. The FSTC initiated a new issue report to document the misclassification of the original issue report and to complete the investigation of the valve malfunction.

On June 28, the FSTC made a presentation to the Plant Operation and Safety Review Committee (POSRC) describing the failed surveillance test and the actions he had taken. The inspectors observed the meeting. During the presentation, the POSRC expressed several concerns. The committee questioned why the valve had not been declared inoperable when the valve failed to stroke full open. The POSRC noted that crediting the flow verification test results involved an assumption that the valve would continue to fail at the same 60% open position. In addition the committee questioned the statistical confidence that the valve would continue to perform normally since the cause of the valve malfunction had not been determined and corrected.

The POSRC chairman promptly briefed the Plant General Manager of the committee's concerns. The Plant manager then directed that a formal functional evaluation of 2-SW-5208-CV be performed in accordance with NO-1-106.

On July 1 the valve failed to stroke full open during testing. The valve again failed at the 60% open position. Operators performed four additional strokes where the valve failed at the 60% open position. The valve stroked full open on the next attempt. Again, during the period that the valve was malfunctioning, the operators performed the OI-29 flow verification test that indicated adequate flow through the valve while only 60% open. The valve was not declared inoperable.

On July 3, Operations began to stroke test the valve open daily. The valve continued to function properly during the remainder of the inspection period. On July 7, system engineers completed the formal functional evaluation of 2-SW-5208-CV. The engineers concluded that adequate flow would be provided to the 22 component cooling water heat exchanger assuming that the valve would continue to fail at the 60% open position. This conclusion was based on a computer flow model using "worst case" conditions for heat exchanger flow. BGE subsequently substantiated this conclusion by actual salt water system branch line flow measurements for various 2-SW-5208-CV open positions. BGE intended to replace the valve actuator but were still awaiting replacement parts when the period ended.

The inspectors found several weaknesses associated with BGE'S initial response to the valve malfunction. These weaknesses included the following:

- When the valve malfunctioned both in June and July, the valve was not declared inoperable by the control room operators even though the valve would not stroke full open as required by the surveillance test used to demonstrate operability. This weakness was not recognized by operations management following the first occurrence even though the malfunction was detailed in the control room logs.

- In both instances, the operators did not declare the valve inoperable based on the results of a flow verification test which involved the assumption that the valve would always fail at the 60% open position without knowing the cause of the malfunction. This assumption remained unchallenged by operations management and system engineering until the June 28 POSRC meeting.

- In both instances, the operators did not declare the valve inoperable based on the results of the OI-29 flow verification test. However, BGE design engineers had previously determined that this test should not be used to determine operability. In a Design Engineering memorandum dated November 23, 1993 the Mechanical Engineering Unit (MEU) stated the following regarding the flow verification methodology contained in OI-29. "MEU does not feel that the procedure outlined in this memo is sufficient to conclusively demonstrate component operability. The information provided can be used to show that the system is responding as predicted within a given range and can be used for flow trending." The plant operators were not aware that the OI-29 test could not conclusively determine operability.

- The IAU screeners incorrectly classified the initial issue report as "hardware only" and therefore BGE missed an early opportunity to have this malfunction formally evaluated for functionality.

- Operations personnel, the responsible system engineers, and the IAU screeners demonstrated a lack of awareness of statistical significance. They did not recognize that the completion of a few successful valve strokes after several failures was not adequate to establish statistical confidence of operability given that the cause of the valve malfunction had not been determined and corrected. In 1994, the NRC identified this insensitivity to statistical significance following an auxiliary feedwater turbine throttle valve malfunction (see NRC Inspection Report 50-317/94-29 and 318/94-28). BGE's prior actions to correct this weakness were not completely successful.

- There were several instances of inadequate communications. Operations was not aware that the original maintenance order had been force closed. BGE did not assure that the November 23, 1993, MEU memorandum was communicated to plant operators. Prior problems regarding statistical significance were not communicated throughout the system engineering organization.

The inspectors concluded that BGE's actions following the June 28 POSRC meeting were prompt and appropriate with the exception of failing to declare the valve inoperable after the failure to meet the surveillance test acceptance criteria during the July 1 test. The POSRC's questioning attitude was noteworthy. The flow testing performed conclusively demonstrated that adequate saltwater flow would be provided to the 22 component water heat exchanger if 2-SW-5208-CV only stroked open to the 60% open position. The daily stroke testing of the valve would provide for early identification of further valve degradation. BGE was in the process on implementing corrective actions for the weaknesses identified above when the period ended.

b. Degraded Expansion Joint

On April 14, 1995, a fire burned through a degraded wall expansion joint that also served as a fire barrier (see NRC Inspection Report 50-317 and 318/95-03). The correct configuration of the wall expansion joints consisted of cork filler material with either metal plates or sealant on both outer sides of the joint. Following the fire, BGE identified several additional degraded expansion joints. The BGE fire protection engineer concluded that joints with either a sealant applied or metal plates on at least one side of the joint were acceptable. This determination is under NRC review as Unresolved Item 50-317 and 318/95-03-02. BGE established fire patrols in those plant areas where the acceptance criteria was not met.

On June 9, a plant operator identified that the metal plates on both sides of the expansion joint between the 11 and 12 emergency diesel generator (EDG) rooms had been pulled back exposing the cork filler material. The operator documented the problem on an issue report and hung a deficiency tag on the degraded joint. The issue report was reviewed by the shift supervisor. Neither the operator nor the shift supervisor considered the degraded joint an operability concern. The IAU subsequently screened the issue report as "hardware only" and a maintenance order was generated to repair the joint.

On July 5, the inspectors noted the degraded joint and questioned whether a fire patrol had been established in the affected EDG rooms. The inspectors found that fire patrols had not been established for these rooms. BGE subsequently initiated fire patrols in the room and initiated a functional evaluation of the degraded joint.

BGE subsequently repaired the joint. The NO-1-106 evaluation of the degraded joint was still under supervisory review when the period ended.

The inspectors found that BGE's slow response to the degraded expansion joint was the result of inadequate communications. Plant operators and the IAU screeners were not aware of the acceptance criteria for expansion joint operability established by the fire protection engineer following the April 14 fire. The fire protection engineer had documented the acceptance criteria in his response to the issue report written to document the fire. The inspectors concluded that if this acceptance criteria had been documented in a NO-1-106 functional evaluation, the operators could have properly classified the degraded joint as an operability concern when the problem was first identified.

Overall, the inspectors concluded that BGE was not always aggressive in pursuing functional evaluations for degraded plant components that had the potential to adversely impact plant safety. Weaknesses in communications between site organizations contributed to both problems. Information regarding equipment operability was not clearly communicated from the engineering organizations to operations staff. The inspectors also noted there continued to be a continuing insensitivity to statistical significance in several site organizations including the IAU, operations, and system engineering.

5.0 PLANT SUPPORT (IPs 92904, 83750, 71750)

5.1 Radiological Controls

The inspectors reviewed selected areas of the radiological controls program including action on previous inspection findings, radiological controls program performance during the recent Unit 2 outage, program changes and oversight activities, organization and staffing, training and qualifications, external and internal exposure controls, and radioactive material and contamination controls.

5.1.1 Changes

The inspectors reviewed selected radiological controls program changes implemented by BGE since the previous inspection in this area. Areas reviewed included organization and staffing, facilities and equipment, and procedure changes.

The inspectors noted that no significant changes were made since the previous inspection. However, during the review, the inspectors noted that BGE implemented a quality assurance plan change in June 1994 which permitted second-line supervisors to fill supervisory positions even though the individuals did not possess a minimum of four years of experience in the craft or discipline supervised as required by the Technical Specifications. The inspectors did not identify any immediate safety concerns in the area of radiological controls in that supervisors selected for review met applicable Technical Specification requirements. However, the inspectors indicated this matter would be further reviewed in that it appeared that second-line supervisors should possess four years of applicable experience. This matter will be reviewed during a subsequent inspection.

5.1.2 Oversight Activities

The inspectors selectively examined BGE's radiological controls program oversight activities including, audits, surveillances, self-assessments, and industry peer evaluations.

Overall, the inspectors determined that very good program oversight activities were implemented. BGE performed numerous surveillances of ongoing radiological controls' activities. No significant audit/surveillance findings were noted. The inspectors noted that BGE's audit group lost its radiation protection experienced individual in June 1994 and that they were attempting to develop discipline-specific proficiency in their audit personnel (i.e., each individual would be proficient in one or more disciplines for audit purposes). The inspectors noted that BGE performed special audits of selected program areas that they believed could benefit from enhancements (e.g., occupational exposure reduction program in January 1995).

The following matter was brought to BGE's attention:

- The inspectors' review of the audit program relative to 10 CFR 20.1101 (c) indicated there was no apparent clear definition as to the content of the radiological controls program for audit purposes. Although the inspectors did not identify any apparent aspects of the program that were not appropriately audited, it was not clear to the inspectors that BGE's audit program was sufficiently defined to ensure periodic audits of all appropriate program content. BGE indicated this matter would be reviewed.

5.1.3 External and Internal Exposure Controls

The inspectors selectively reviewed the implementation and adequacy of external and internal exposure controls at Units 1 and 2 including performance associated with completed outage work activities at Calvert Cliffs Unit 2. The review was with respect to criteria contained in applicable BGE procedures and 10 CFR Part 20, Standards for Protection Against Radiation.

The inspectors toured the radiologically controlled areas of the plant and reviewed, as appropriate, the following: posting, barricading and access control to radiation, high radiation, and airborne radioactivity areas; personnel adherence to radiation protection procedures, radiation work permits, and radiological control practices; use and placement of dosimetry devices; use of respiratory protection equipment; assessment of internal exposure (as appropriate); maintenance of individual airborne radioactivity tracking logs; and adequacy of radiological surveys to support ongoing work.

The inspectors' review indicated that, overall, good radiological controls were implemented for the outage. BGE had sustained 135 personnel contaminations for 1995 as of June 30, 1995. The contaminations did not result in any significant personnel radiation exposure. BGE's personnel contamination monitcring program provided for monitoring of beta and gamma emitting radioactive contamination prior to egress from the station.

The inspectors identified the following areas for improvement relative to identification, documentation, and evaluation of personnel contamination:

- The inspectors' review indicated that approximately 46% percent of the radionuclide mix that personnel would likely encounter consisted of hard to detect radionuclides (e.g., Cr-51) which were difficult to detect with beta sensitive radiation monitoring devices but were detectable with gamma sensitive radiation monitoring devices. The inspectors noted that BGE detected an individual entering the station on April 15, 1995 with contamination of the left shoe. Contamination levels indicated 50,000 disintegrations per minute (dpm) using a gamma sensitive radiation monitoring device and 6,000 dpm using a beta sensitive monitoring device. The individual had been working in the radiologically controlled area (RCA) the previous day. It was not clear to the inspectors how the individual managed to leave the RCA and the station with the contaminated shoe. BGE had initiated an investigation of this matter including taking corrective actions. The ongoing investigation precluded complete inspector review of this matter at this time.

The inspectors' review of several personnel contamination reports indicated the following:

- It was unclear in several reports as to the total amount of radioactivity present on the skin.

- Differences in personnel contamination readings as indicated on the personnel contamination forms were not explained.

- BGE was not using resolving time correction factors for beta sensitive contamination monitors when monitoring significant levels of skin contamination.

- The contamination documentation form was not structured to ensure documentation of important aspects of the contamination as indicated in procedures.

- In some cases, the technical basis for skin dose assessment was not documented, nor was it clear what the assigned exposure to the skin was.

- The inspectors identified one example involving a personnel contamination that was not finally reviewed and signed-off for three months. The example was open as of the date of the inspection.

- It was not apparent that original documentation was properly controlled.

BGE initiated a review of the above matters.

The inspectors also noted isolated inconsistencies in posting of radiological information within the station. BGE also initiated a review of this matter.

5.1.4 Radioactive Material and Contamination Controls

The inspectors reviewed the adequacy and effectiveness of BGE's controls for radioactive material and contamination at Units 1 and 2. Items reviewed included personnel frisking practices; use of proper contamination control techniques at work locations, including control of hot particles; posting and labeling (as appropriate) of radioactive and radioactive material; BGE's efforts to reduce the volume of contaminated trash, including steps to minimize introduction of unnecessary material into potentially contaminated areas; and BGE self-identified findings in the area of radioactive material and contamination control.

The evaluation of BGE's performance in this area was based on independent observations by the inspectors during station tours, discussions with cognizant personnel, and review of documentation.

The inspectors' tours indicated BGE provided generally effective radioactive material and contamination controls. Overall, the station appeared to have minimal contaminated area. At the time of the inspection, BGE considered approximately 3% (approximately 4,000 square feet) of its radiologically controlled area to be contaminated. BGE was tracking 17 leaks and 12 "hot spots" for monitoring and corrective action purposes, as appropriate.

The following matter was brought to BGE's attention:

- There was no apparent clearly defined program (e.g., central file) to provide for documentation and tracking of onsite spills of contamination relative to 10 CFR 50.75 (g) for decommissioning purposes. The inspector questioned this matter when requesting documentation on a previous spill associated with an outdoor water storage tank. The spill residue had apparently been cleaned up and properly disposed.

The above matter will be reviewed during a subsequent inspection.

5.1.5 ALARA Program

The inspectors reviewed selected aspects of BGE's program to maintain personnel occupational radiation exposures as low as is reasonably achievable (ALARA). The principal focus of the review was the evaluation of BGE's performance during the 60-day Unit 2 outage (March - May 1995). The evaluation of BGE's performance was based on discussions with cognizant personnel, independent inspector observations during tours of the station, observations of ongoing work activities (as appropriate), and review of documentation.

The inspectors noted that BGE had sustained a total aggregate exposure of 458 person-rem for 1994 as compared to a goal of 405 person-rem. BGE attributed the overage to emergent work and some rework. To improve overall performance, they had initiated a number of occupational exposure reduction initiatives since early 1994. These included the following:

- Implementation of a new radiation work permit program.
- Implementation of a scaffold reduction initiative.
- Focus on reducing high radiation area entries.
- Use of a computerized access control and real-time radiation monitoring system.
- Installation of new neutron shields for the Unit 1 and Unit 2 reactor cavities.
- Establishment of a leakage and hot spot control program.
- Establishment of a site ALARA committee.
- Performance of a comprehensive decontamination of the Unit 2 containment.
- Close monitoring of station performance relative to industry peers.
- Implementation of outage scope control methods.
- Development of station work group occupational exposure reduction plans.
- Implementation of performance-based ALARA incentives for personnel.

The inspectors noted that BGE had implemented a five-year ALARA Plan on January 1, 1993, and was updating the plan. BGE was also implementing a cobalt reduction program.

BGE sustained an aggregate exposure for the Unit 2 refueling outage of 187.6 person-rem as compared to an outage goal occupational exposure goal of 270 person-rem. The baseline (i.e., required refueling outage activities) Unit 2 refueling outage exposure goal was 220 person-rem. However, the actual aggregate exposure received for baseline activities was only approximately 160 person-rem. BGE had not anticipated such very good performance but attributed the improved performance, in part, to the above initiatives as well as to a shortened outage duration (with generally the same amount of work). BGE was continuing to evaluate the causes for the improved performance at the end of the inspection. Attachments 4 and 5 provide the historical record regarding site dose and refueling outage estimates which document the improved performance noted.

The inspectors noted that BGE's efforts to reduce personnel occupational radiation exposures were effective. The following areas for enhancement were noted:

- The inspectors reviewed the 1994 Unit 1 post-outage report, the Unit 2 1995 pre-outage plan, and the draft Unit 2 1995 post-outage report. The inspectors' review indicated there was no clear connection between the 1994 Unit 1 post-outage ALARA report, the 1995 Unit 2 pre-outage ALARA plan, or the draft 1995 Unit 2 post-outage report that clearly identified lessons learned and dose reduction techniques for future use or their effectiveness.

- It was not apparent that the licensee was routinely using, as appropriate, cost-benefit evaluations of occupational exposure reduction initiatives for exposure over the life of the station. The inspectors noted that current efforts appeared to be limited to major capital expenditure items.

5.1.6 General Plant Tour Observations

The inspectors toured the station during the inspection. The inspectors' review indicated that the station exhibited overall very good radiological housekeeping. However, the inspectors noted that seals around the auxiliary building/containment interface were deteriorating. The inspectors questioned the potential impact of degrading seals on offsite doses following an accident. The inspectors noted that the seals were blocked from the inside and had been reviewed for fire protection and floods but apparently not for radioactive releases. The inspectors noted bins of parts at the miscellaneous waste evaporator. It was not clear why the loose parts were stored in the area. BGE indicated these matters would be reviewed.

5.2 Fire Protection

BGE discovered that the training certifications of all of their Fire & Safety technicians (FSTs) to perform surveillance testing had expired. The issue was an unresolved item (URI 95-05-03) from NRC Inspection Report 50-317 and 318/95-05 pending completion of NRC review.

FST requirements for maintaining certification were delineated in the BGE "Test and Inspection Personnel Qualification Manual" (formerly Calvert Cliffs Instruction 613, "Qualification of Test and Inspection Personnel"). The Qualification Manual required that personnel performing inspection and testing activities receive a performance evaluation within the last twelve months and recertification at intervals not to exceed three years. Performance continuity and recertification would be documented on a "Certificate of Qualification - Recertification Approval" by the individual's supervisor.

The inspectors reviewed the training records for the Safety & Fire Protection Unit and verified that the twelve month performance evaluations and triennial recertifications had expired at various times from 1991 until March 1995 and had not been renewed. FST qualification cards were not found in the record files for four of the 13 FSTs, and one card was not completely filled out. There was not an established method for documenting performance observations, and there was no record of who, when, or what surveillance test procedures (STPs) had been observed by the unit supervisor.

Part of the FST qualification card was a list of STPs and preventive maintenance tasks (PMs). One card revision required trainees to review and assist in the performance of the STPs and PMs prior to being qualified to perform them. Another card revision required participation in the STP and a review of its scope and purpose with the Fire Protection Specialist or the Supervisor - Safety & Fire Protection Unit before being qualified to perform the STP. Most individuals had not completed the entire STP list, and as a result were not qualified to perform all STPs. Inspectors reviewed the most recently completed copies of the 35 fire protection STPs and found three that had been signed off by individuals who had not completed the STP on their qualification cards. In each case, the individuals were qualified to do the tasks required of the STP, such as testing smoke detectors, but had performed the STP for qualification purposes on a different unit or in a different fire zone.

The inspectors discussed the issue at length with the Principal Engineer - Plant Testing Unit and the Supervisor - Safety and Fire Protection Unit. Apparently, training records retention had been transferred from the safety and fire protection line unit to the technical training unit in the 1992 time frame, and records had not been updated since then. BGE did not find any other units with the same loss of continuity in records upkeep. BGE had developed a corrective action plan to improve the Safety & Fire Protection Unit's performance with respect to STPs and was in the process of revising the training and qualification manual for fire and safety staff. The inspectors reviewed the plan and milestones and noted that it appeared to address the issue satisfactorily. The inspectors concluded that there was minimal safety concern because all completed STPs were reviewed by a qualified reviewer, and there were no indications that fire system STPs were being performed improperly.

However, the inspectors assessed that there were significant weaknesses in the documentation of FST qualification and recertification due to a longstanding lack of supervisory oversight of the qualification program. Criterion V of 10 CFR 50, Appendix B, requires that activities affecting quality be prescribed by documented instructions or procedures and that such activities would be accomplished in accordance with those instructions or procedures. The requirement was implemented, in part, by the BGE Test and Inspection Personnel Qualification Manual, which required that "personnel who conduct inspection, examination, and tests...must be qualified" in accordance with the manual. The failure to maintain FST qualifications in accordance with the Qualification Manual and to adequately document such qualification is a Violation of NRC requirements (VIO 95-06-03). While the Violation meets the criteria for discretion specified in Section VII of the NRC Enforcement Policy, it is being cited because of the apparent failure of supervision to maintain cognizance of the qualification program over such a long period of time. Unresolved Item 95-05-03 is administratively closed.

6.0 SAFETY ASSESSMENT AND QUALITY VERIFICATION (IP 40500)

The inspectors noted excellent supervisory oversight of the two major challenges to plant operations this period, caused by some equipment problems that affected Unit 2, and high bay water temperatures that affected both units. BGE demonstrated good judgement, excellent plant control, and strong safety perspective in resolving both challenges.

The good performance exhibited in resolving the two major challenges was contrasted, however, by apparent failures in supervisory oversight of more routine, less dynamic responsibilities regarding control of plant drawings, qualification of personnel to perform fire system surveillance testing, and foreign material exclusion control. Many drawings in the control room and in the plant used to operate the plant safely were found to be missing or were the wrong revision. The qualifications of all fire and safety technicians to perform fire system surveillance testing were allowed to expire without renewal over a four year period. Finally, a failure to implement foreign material exclusion controls on the new station blackout diesel indicated that BGE's efforts to adequately implement the foreign material control program were not fully successful.

The inspectors assessed that the contrast indicated that BGE continued to exhibit good management of emergent, high visibility issues, while they continued to be less successful in meeting management expectations and resolving longstanding deficiencies in some lower visibility programs. This was considered a weakness in the most recent Systematic Assessment of Licensee Performance Report 50-317 and 50-318/93-99.

7.0 REVIEW OF WRITTEN REPORTS (IPs 90712, 92700)

The inspectors reviewed LERs and other reports submitted to the NRC to verify that the details of the events 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 onsite follow-up. The following LERs were reviewed:

Units 1 and 2:

LER 92-004, Revision 2: Inoperable Fire Dampers Due to Conflicting Design Information.

Unit 1:

LER 95-002: Manual Trip Due to Loss of 12 Steam Generator Feed Pump. The event was reviewed in NRC Inspection Report 50-317 and 318/95-05.

The above LERs were reviewed with respect to the requirements of 10 CFR 50.73 and the guidance provided in NUREG 1022. Generally, the LERs were found to be of high quality with good documentation of event analyses, root cause determinations, and corrective actions.

10 CFR Part 21 Reports

In a letter dated July 12, 1995, Rosemount Nuclear Instruments made a Notification under 10 CFR Part 21, concerning a revision dated October 1992, to Instruction Manual 4235 for the Model 1152 Nuclear Qualified Transmitter. The Model 1152HP high differential pressure transmitters were manufactured with the correct process O-rings; however, the revision to the instruction manual inadvertently specified an incorrect process O-ring. BGE used the

Model 1152HP transmitters to monitor pressurizer level and reactor coolant system flow. BGE verified that no maintenance had been performed on their transmitters which would have required replacing the suspect O-ring and revised the instruction manual to reflect the correct O-ring.

8.0 FOLLOW-UP OF PREVIOUS INSPECTION FINDINGS

Licensee actions taken in response to open items and findings from previous inspections were reviewed. The inspectors determined if corrective actions were appropriate and thorough and previous concerns were resolved. Items were closed where the inspectors determined that corrective actions would prevent recurrence. Those items for which additional licensee action was warranted remained open. The following items were reviewed and closed.

8.1 Engineering

(Closed) Violation 50-317 and 318/93-31-01: Failure to Promptly Resolve Safety Concerns with the Makeup Sources to the Service Water System.

The issue involved an example of weak issue resolution that potentially affected the operability of the service water system under certain accident conditions. Based on BGE's corrective actions for the specific issue, as verified by the inspectors, and continued improvement in their corrective action system, as documented in NRC Inspection Report 50-317 and 318/95-02, the Violation is closed.

(Closed) Unresolved Item 50-317 and 318/95-05-01: Problems with the control of plant drawings.

The inspectors reviewed this item during the period and documented the results of this review in section 4.1. This item is administratively closed and Violation 50-317 and 318/95-06-02 opened.

8.2 Maintenance

(Closed) Unresolved Item 50-318/95-03-01: Ultrasonic Coverage of Required Weld Inspection Volume.

The issue was reviewed and closed as documented above in section 3.3.

8.3 Plant Support

(Closed) Unresolved Item 50-317 and 318/95-05-03: Certification of Fire and Safety Technicians to perform STPs.

Upon completion of NRC's review, this issue is administratively closed as discussed in section 5.2 above and Violation 50-317 and 318/95-06-03 is opened.

9.0 MANAGEMENT MEETING

During this inspection, periodic meetings were held with station management to discuss inspection observations and findings. At the close of the inspection period, an exit meeting was held to summarize the conclusions of the inspection. No written material was given to the licensee and no proprietary information related to this inspection was identified.

A management meeting was held between BGE and the NRC on July 26 at the Calvert Cliffs Visitors Center to discuss the results of the NRC Systematic Assessment of Licensee Performance (SALP) Report for the period October 10, 1993, to May 13, 1995. The meeting was open to the public. The slides presented at the meeting by the NRC and BGE are Attachments 2 and 3, respectively, to this report.

9.1 Preliminary Inspection Findings

Three violations were identified, regarding control of plant drawings, qualification of fire and safety technicians to perform surveillance testing, and foreign material control. Two unresolved items associated with these issues were administratively closed. In addition, an unresolved item regarding ultrasonic coverage of welds was closed.

ATTACHMENT 1

Routine Maintenance and Surveillance Observations

STP O-8A-1	11 EDG and 4kV Bus 11 LOCI Sequencer Test
STP M-213-2	Calibration of Power Range Nuclear Instrumentation by Comparison with Incore Nuclear Instrumentation
STP O-47-2	MSIV Partial Stroke Test
STP O-5-1	Auxiliary Feedwater System Test
STP M-212-2	RPS Functional Test
MO 1199501720	Clean 12 Service Water Heat Exchanger Tubes
MO 1199501719	Clean 12 Component Cooling Water Heat Exchanger Tubes
MO 0199402809	Inspect Turbochargers on 12 Emergency Diesel Generator (EDG)
MO 0199501070	Replace 12 EDG Governor Oil Booster
MO 0199501190	Replace Fuel Oil Filters
MO 1199404305	Inspect and Lubricate 12 Low Pressure Safety Injection Pump Coupling
MO 2199502536	Replace hydraulic solenoid dump valves on 22 MSIV
MO 0199400921	Vacuum Dry DSC No. 10
MO 5199500161	Perform the Two Year Inspection on the OC Diesel
MO 2199502425	Clean 22 SRW Heat Exchanger tubes
MO 2199502424	Clean 22 CC Heat Exchanger tubes
MO 0199302426	Replace 21 EDG Control Relays
MO 2199404012	Inspect MCC 21G Breakers and Controllers
MO 0199100785	Install New Temperature Switches for EDG Lube Oil
MO 2199406137	Replace 21 EDG Generator Bearing TIS-4799

ATTACHMENT 2

Slides Presented by BGE and NRC at the July 26 SALP Meeting

UNITED STATES NUCLEAR REGULATORY COMMISSION

SYSTEMATIC ASSESSMENT OF LICENSEE PERFORMANCE (SALP)

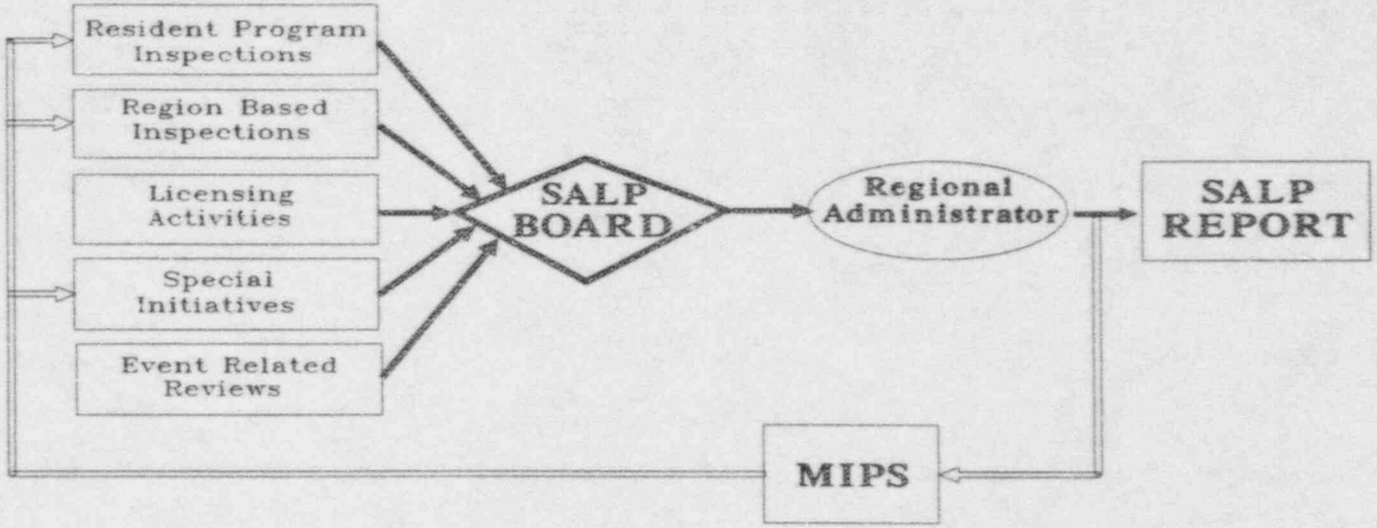
FACILITY NAME
CALVERT CLIFFS NUCLEAR POWER PLANT

ASSESSMENT PERIOD: OCTOBER 10, 1993 - MAY 13, 1995
BOARD MEETING: MAY 31, 1995
MANAGEMENT MEETING: JULY 24, 1995

AGENDA

NRC INTRODUCTORY REMARKS:	***W. F. Kane*** ***Deputy Regional Administrator***
BGE INTRODUCTORY REMARKS:	***R. E. Denton*** ***Vice President - Nuclear Energy***
NRC SALP PROCESS & RESULTS:	***W. D. Lanning*** ***Deputy Director, Division of Reactor Projects***
BGE CLOSING REMARKS:	***R. E. Denton***
NRC CLOSING REMARKS:	***W. F. Kane***
PUBLIC QUESTIONS AND ANSWERS:	***NRC***

NEW SALP PROCESS



PERFORMANCE ANALYSIS AREAS FOR OPERATING REACTORS

- **Plant Operations**
- **Engineering**
- **Maintenance**
- **Plant Support**
  - Radiological Controls
  - Emergency Preparedness
  - Security
  - Fire Protection
  - Housekeeping

PERFORMANCE CATEGORY RATINGS

Category 1: Superior Performance

- Programs and Procedures Provide Effective Controls
- Self-Assessment Efforts are Effective
- Corrective Actions are Comprehensive
- Minimum Inspections to Verify Safety

Category 2: Good Performance

- Programs and Procedures Normally Provide Controls
- Self-Assessment Efforts are Good - Emerging Issues
- Recurring Issues
- Additional Inspection to Assess Performance

Category 3: Acceptable Performance

- Programs and Procedures are Weak
- Self-Assessment Efforts are Reactive
- Corrective Actions less than Adequate
- Significant NRC and Licensee Attention Required

Performance Analysis

Functional Area	Rating Last SALP	Rating This SALP
Plant Operations	1	1
Maintenance	2	2
Engineering	1	1
Plant Support	2	2

PLANT OPERATIONS
Category 1

- OPERATOR PERFORMANCE CONTINUED TO BE A STRENGTH

- SELF-ASSESSMENTS WERE THOROUGH AND IDENTIFIED AREAS WHERE PERFORMANCE COULD BE ENHANCED:
  - WORK CONTROL CENTER MOVED OUTSIDE CONTROL ROOM
  - PROCEDURE IMPROVEMENTS
  - IMPROVEMENTS TO SHIFT TURNOVER PROCESS

- SCHEDULING, PLANNING AND IMPLEMENTATION OF THE LAST REFUELING OUTAGE WAS EXCELLENT WITH STRONG SUPPORT BY OPERATIONS STAFF. BOTH OUTAGES DURING THE PERIOD WERE EVENT FREE.

- OPERATING EXPERIENCE REVIEW GROUP PROVIDED STRONG OVERSIGHT AND PROVIDED DETAILED RECOMMENDATIONS

MAINTENANCE
Category 2

- MANAGEMENT ATTENTION PRODUCED MEASURABLE REDUCTIONS IN BACKLOG AND CONTROL ROOM DEFICIENCIES
- WORK CONTROL PROCESS HAD STRONG SAFETY FOCUS AND PROVIDED GOOD RISK INSIGHTS
- MAINTENANCE AND SURVEILLANCE ACTIVITIES CONTINUED TO PROVIDE CHALLENGES TO PLANT OPERATIONS
- PREVENTIVE MAINTENANCE PROGRAM FOR BALANCE-OF-PLANT EQUIPMENT WAS NOT ALWAYS SUCCESSFUL IN IDENTIFYING DEGRADED COMPONENTS
- SOME PERSONNEL PERFORMANCE ISSUES HAVE NOT YET BEEN FULLY RESOLVED

ENGINEERING
Category 1

- WELL FOCUSED SELF ASSESSMENTS WERE EFFECTIVE IN IMPROVING THE TIMELINESS AND QUALITY OF ENGINEERING WORK PRODUCTS

- ROOT CAUSE ANALYSIS PROGRAM CONTINUED TO BE VERY GOOD

- MODIFICATION DESIGN DOCUMENTS AND SAFETY EVALUATIONS WERE OF HIGH QUALITY

- CORRECTIVE ACTIONS FOR WEAKNESSES IDENTIFIED EARLY IN THE PERIOD APPEAR TO HAVE BEEN EFFECTIVE

- ENGINEERING SUPPORT TO THE MOV AND S/G TUBE INSERVICE INSPECTION PROGRAM WERE GOOD

- SERVICE WATER SYSTEM SELF ASSESSMENT WAS EXCELLENT

PLANT SUPPORT
Category 2

- ALARA HAS BEEN A CONTINUING PROBLEM WITH NOTABLE IMPROVEMENT IN THE LAST REFUELING OUTAGE

- RADIOLOGICAL ENVIRONMENTAL MONITORING PROGRAM AND RADIOLOGICAL EFFLUENTS CONTROL PROGRAM CONTINUED TO BE EXCELLENT

- EMERGENCY PREPAREDNESS HAS IMPROVED, ALTHOUGH SOME WEAKNESSES WERE NOTED

- IMPLEMENTATION OF THE FIRE PROTECTION PROGRAM WAS GOOD

- HOUSEKEEPING RANGED FROM GOOD TO EXCELLENT

- SECURITY PROGRAM PERFORMANCE APPEARS TO HAVE DECLINED

BALTIMORE GAS AND ELECTRIC COMPANY

CALVERT CLIFFS NUCLEAR POWER PLANT

Systematic Assessment of Licensee Performance

Management Meeting: July 26, 1995

BGE

ATTACHMENT 3

EXCELLENT RESULTS IN OPERATIONS & ENGINEERING

Operations

- Management Involvement
- Self-Assessments
- Operator Response

Engineering

- Management Involvement
- Safety Perspective
- Talented Staff

Oversight/Safety Assessment

BGE

OPPORTUNITIES FOR IMPROVEMENT PREVIOUSLY IDENTIFIED

- Corrective Action System
- ALARA Integration and Management Support
- Maintenance Specifics (QV, FME, Work Control, NDE)

BGE

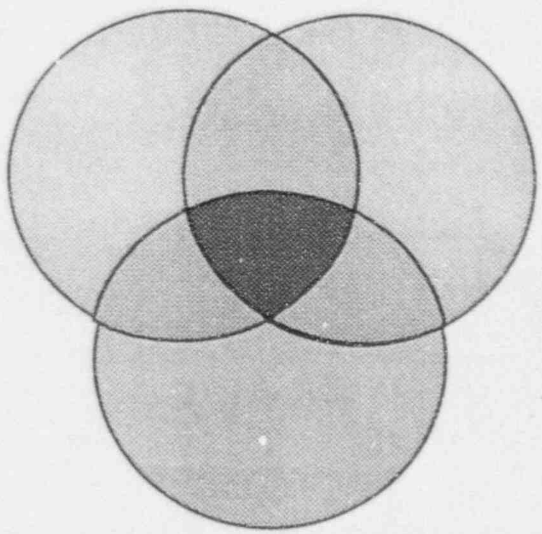
AREAS FOR CONTINUED IMPROVEMENT

- Trip Prevention Program
- Human Performance Enhancements
- Equipment Performance Improvements
- Security

BGE

VISION: "To Perform As A World Class Energy Facility"

Industrial Safety:
OSHA Recordables =
Top Quartile



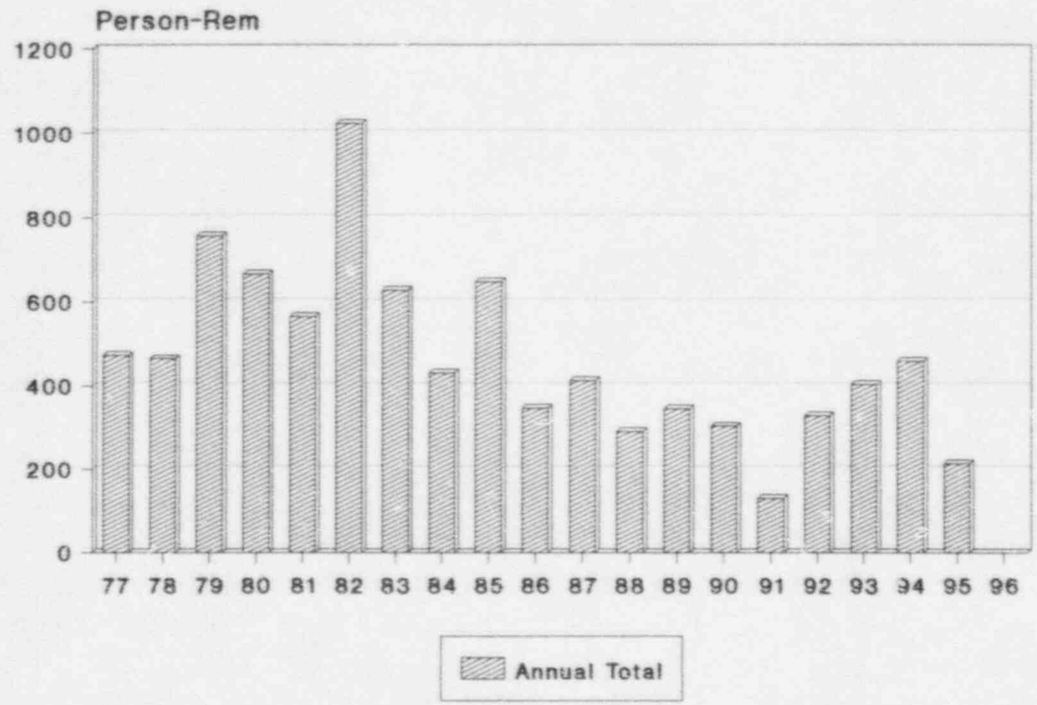
Nuclear Safety/
Regulatory Assessment:
SALP = Top Quartile
INPO = "1"

Cost Competitive:
TSAE = Best
Third

ATTACHMENT 4

Baltimore Gas & Electric
Calvert Cliffs
Nuclear Power Plant
Lusby, MD 20657

SITE DOSE 1977 - 1997

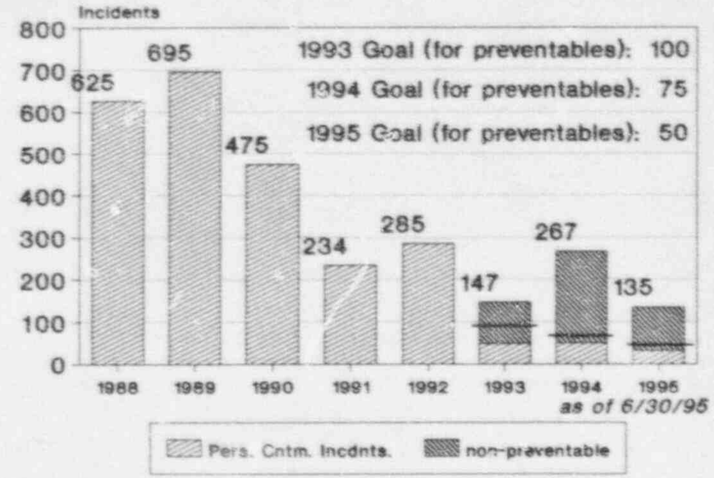


DOSHISTS.CHT

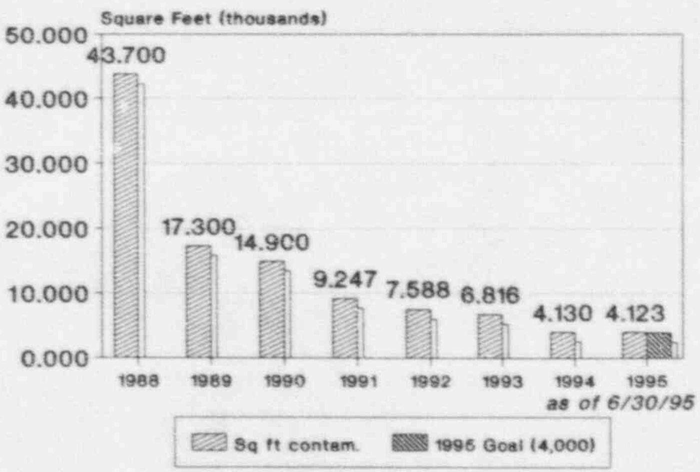
as of 6/30/95

RAD SAFETY

PCIs 1988 - 1995



CONTAMINATION AREA 1988 - 1995



Total area considered: *127,787 sq ft*

U2 10th RFO DOSE ESTIMATE

Dose Category	U2 10th "Goal"	U1 11th	Last 3 Avg.	U2 10th Est. Original	After Improvements
Baseline Refueling	*210.0*	268.2	227.0	250.0	223.6
Plant Modifications	*30.0*	88.4	92.2	37.0	40.0
Contingency	*10.0*	10.7	10.2	10.0	10.0
Grand Total	*250.0*	367.3	329.4	300.0	273.6
BASELINE REFUELING					
Refueling	*65.0*	76.9	71.6	70.0	65.1
S/G Maintenance	*18.0*	19.8	29.3	22.0	21.3
RCP Maintenance	*11.0*	11.8	11.2	13.0	13.0
Valve Maintenance	*15.0*	16.5	14.3	22.0	20.9
ISI / Snubbers	*24.0*	7.7	7.8	42.0	29.4
Radiation Safety	*30.0*	40.0	30.6	35.0	30.0
Minor Maintenance	*23.0*	22.2	22.5	22.5	21.8
Scaffold & Insulation		48.4		^(45)	^(31.5)
Miscellaneous	*24.0*	24.9	23.6	23.5	22.1
SUB-TOTAL	*210.0*	268.2	227.0	250.0	223.6
MODIFICATIONS / PROJECTS					
Neutron Shield	*16.5*	16.9		16.5	16.5
2CVC519 Bypass	*2.0*			2.0	2.0
RCP Oil Fill Lines	*2.0*			2.0	2.0
Electrical Pen. 2ZEB1	*1.0*			1.5	1.5
PIA-118 (MCR)	*4.0*			*11.0	11.0
UGS Lift Rig (MCR)	*2.0*			4.0	4.0
Other	*2.5*	71.5	86.5	3.0	3.0
SUB-TOTAL	*30.0*	88.4	92.2	40.0	40.0
CONTINGENCY					
Contingency	*10.0*	10.7	10.2	10.0	10.0
SUB-TOTAL	*10.0*	10.7	10.2	10.0	10.0

Minor Maintenance	U-1 11th
General Areas	6.2 Rem
High Rad Areas	9.7 Rem
Aux. Bldg.	6.3 Rem
TOTAL	22.2 Rem

Miscellaneous (Highlights)	U-1 11th
Air Cooler Maint.	2.8 Rem
Transmitter Maint.	1.0 Rem
Inspections/Tours	6.7 Rem
Operations	3.5 Rem
Tools/Equipment	5.4 Rem
Airlocks/Cranes/Hatches	2.9 Rem
TOTAL	24.8 Rem

*Assumes failure of root tap.

^Scaffold dose distributed to paths:

S/G Maint.	3.0 Rem
RCP Maint.	2.0 Rem
Valve Maint.	5.0 Rem
ISI/Snubbers	35.0 Rem

7/12/95