U.S. NUCLEAR REGULATORY COMMISSION
REGION I

Report Nos.: 50-317/91-30 and 50-318/91-30

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: November 24, 1991, through January 4, 1992

Inspectors: Allen G. Howe, Senior Resident Inspector
Carl F. Lyon, Resident Inspector
Scot A. Greenlee, Reactor Engineer

Approved by: Larry E. Nicholson 1/14/92
Larry E. Nicholson, Chief Date
Reactor Projects Section No. 1A
Division of Reactor Projects

Inspection Summary:

This inspection report documents resident inspector core, regional initiative, and reactive inspections performed during day and backshift hours of station activities including: plant operations; radiological protection; surveillance and maintenance; emergency preparedness; security; engineering and technical support; and safety assessment/quality verification.

Results:

See Executive Summary.

EXECUTIVE SUMMARY

Calvert Cliffs Nuclear Power Plant, Units 1 and 2

Inspection Report Nos. 50-317/91-30 and 50-318/91-30

Plant Operations: (Operational Safety Inspection Module 71707, Prompt Onsite Response to Events at Operating Power Reactors Module 93702) Operator performance during startup of both units, a shutdown of Unit 1, and a manual trip of Unit 2 that occurred during the period was acceptable. Good initiative and safety consciousness were demonstrated during the response to the failure of the 13 high pressure safety injection pump breaker. A concern was identified with the failure of the Unit 1 emergency air lock interlock (UNR 50-317 and 50-318/91-30-01).

Radiological Protection: (Module 71707) The inspectors concluded, based on selected reviews, that the radiological controls program implementation was acceptable.

Maintenance and Surveillance: (Maintenance Observations Module 62703, Surveillance Observations Module 61726) Overall, maintenance and surveillance activities were performed safely and in accordance with the requirements. One administrative problem regarding procedure controls was properly addressed by the licensee.

Emergency Preparedness: (Module 71707) The inspectors' review of facilities and personnel found an acceptable level of emergency preparedness.

Security: (Module 71707) The inspectors determined that security program implementation was acceptable.

Engineering and Technical Support: (Module 71707) The inspectors determined that safety evaluations regarding increased allowable leakrates on the No. 12B safety injection tank check valve, and the operation of non-radioactive contaminated systems appropriately addressed safety concerns with adequate technical basis. The inspectors determined, and the licensee agreed, that the description in the Final Safety Analysis Report of the portable sampling assembly for main vent effluent particulate sampling was inadequate. The licensee is taking appropriate actions to correct the problem. Engineering support for a saltwater system leak was good.

Safety Assessment/Quality Verification: (Module 71707) A responsible safety perspective was exhibited by the plant staff and management regarding the decision to shutdown Unit 1 to repair the excessive safety injection tank check valve leakage and to trip Unit 2 when steam from a leaking feedwater heater relief valve caused unexpected effects. The Plant Operations Safety Review Committee demonstrated an acceptable level of performance.

DETAILS

1.0 SUMMARY OF FACILITY ACTIVITIES

Unit 1 began the period at full power. On December 21, the unit was shut down and placed in mode 4 (hot shutdown) due to increased leakage through the 12B safety injection tank (SIT) discharge check valve. Following replacement of the discharge check valve O-ring, the unit remained in mode 4 for corrective maintenance on the 12B SIT motor operated outlet valve, which had failed to open during system restoration. The unit was made critical on December 29 and operated at power for the remainder of the period.

Unit 2 returned to full power on November 24 following a scheduled surveillance outage. On January 2, 1992, the unit was manually tripped from 92% power after the 26B feedwater heater tube side relief valve lifted and failed to reseat. Steam subsequently issuing from the turbine building floor drains resulted in DC bus electrical grounds and a low main feed pump suction pressure alarm. The unit was maintained in mode 3 (hot standby) while the event was evaluated and repairs were made to the relief valve. The unit was restarted and paralleled to the grid on January 4.

2.0 PLANT OPERATIONS

2.1 Operational Safety Verification

The inspectors observed plant operation and verified that the facility was operated safely and in accordance with licensee procedures and regulatory requirements. Regular tours were conducted of the following plant areas:

-- control room	-- security access point
-- primary auxiliary building	-- protected area fence
-- radiological control point	-- intake structure
-- electrical switchgear rooms	-- diesel generator rooms
-- auxiliary feedwater pump rooms	-- turbine building

Control room instruments and plant computer indications were observed for correlation between channels and for conformance with technical specification (TS) requirements. Operability of engineered safety features, other safety related systems and onsite and offsite power sources was verified. The inspectors observed various alarm conditions and confirmed that operator response was in accordance with plant operating procedures. Routine operations surveillance testing was also observed. Compliance with TS and implementation of appropriate action statements for equipment out of service were inspected. Plant radiation monitoring system indications and plant stack traces were reviewed for unexpected changes. Logs and records were reviewed to ascertain that entries were accurate and identified equipment status or deficiencies. These records included operating logs, turnover sheets, system safety tags, temporary modifications log, and the jumper and lifted lead book. Plant housekeeping controls were monitored, including control and storage of flammable material and other potential safety hazards. The inspectors also examined the condition of various fire protection, meteorological, and seismic monitoring systems. Control room and shift manning were compared to regulatory requirements and portions of shift turnovers were observed. The inspectors found that control room access was properly controlled and that a professional atmosphere was maintained.

In addition to normal utility working hours, the review of plant operations was routinely conducted during portions of backshifts (evening shifts) and deep backshifts (weekend and midnight shifts). Extended coverage was provided for 24 hours during backshifts and 11 hours during deep backshifts. Operators were alert and displayed no signs of inattention to duty or fatigue.

The inspectors observed an acceptable level of performance during the inspection tours detailed above.

2.2 Followup of Events Occurring During Inspection Period

During the inspection period, the inspectors provided onsite coverage and followup of unplanned events. Plant parameters, performance of safety systems, and licensee actions were reviewed. The inspectors confirmed that the required notifications were made to the NRC. During event followup, the inspectors reviewed the corresponding CCI-118N (Calvert Cliffs Instruction), "Nuclear Operations Section Initiated Reporting Requirements" documentation, including the event details, root cause analysis, and corrective actions taken to prevent recurrence. The following events were reviewed.

a. Saltwater Leak

On November 24, 1991, during normal rounds, a plant operator discovered a through wall leak in the Unit 1 No. 11 saltwater header upstream of the No. 11 service water heat exchanger. Operators isolated the system, declared it inoperable, and entered the associated technical specification action statements. The inspectors reviewed the operator actions and the technical specification requirements and assessed that the operator actions were appropriate.

BG&E initiated actions for a relief from ASME Code requirements as allowed by 10 CFR 50.55a(g)(6)(i) and implemented a temporary non-Code repair of the ASME Code Class 3 piping as authorized by the requirements of Generic Letter (GL) 90-05, as supplemented. The request for code relief was discussed in a teleconference between BG&E and the NRC on November 27, 1991. No significant safety concerns were identified in the teleconference. Subsequent to the teleconference, BG&E placed the system in service and declared the saltwater system operable.

The inspectors reviewed the results of the ultrasonic evaluations of similar locations to identify any other degraded areas and walked down the inspection points with engineering personnel. GL 90-05 requires the inspection of at least five additional points determined to be susceptible to the cause of the failure. BG&E selected seven points and found no other degraded conditions. The inspectors concluded that appropriate selection criteria were used.

The inspectors reviewed the engineering evaluation for the temporary repair (BG&E temporary alteration 1-91-088) and discussed the issue with cognizant BG&E personnel. The evaluation considered flooding, spraying of equipment, loss of flow from the system, and design loading concerns. The inspectors concluded that the concerns were appropriately evaluated and had no additional questions. Overall, BG&E actions were appropriate and consistent with the guidance in GL 90-05.

b. High Pressure Safety Injection Pump Breaker Failure

On November 26, the charging spring on the 13 high pressure safety injection (HPSI) pump breaker failed to recharge after the pump was used to perform the periodic leak test on 12B safety injection tank discharge check valve. The breaker in question, number 152-1410, is located in 4Kv safety bus number 14. The 13 HPSI pump may also be powered from a breaker in 4Kv safety bus number 11. In this case, the number 11 safety train was inoperable because its emergency power supply, 11 emergency diesel generator, was inoperable while the ultimate heat sink, 11 saltwater header, was out of service to repair a leak. The 11 saltwater header also supplies the cooling water that cools the room where the 11 and 12 HPSI pumps are located. This condition resulted in the 11 and 12 HPSI pumps being declared inoperable.

The failure of breaker 152-1410 to recharge actuated the "13 HPSI SIAS (safety injection actuation system) Blocked Auto Start" alarm in the control room. Since both power supplies to 13 HPSI pump were now inoperable, the shift supervisor declared the pump inoperable. With no HPSI pumps operable, Unit 1 entered TS 3.0.3 at 2:00 p.m.

Operators and electrical technicians investigating the problem at breaker 152-1410 found that the closing latch monitoring switch was open, which prevented the charging spring from recharging. They were unable to immediately determine the reason that the switch was open. The electrical work supervisor at the scene noted that the 13 service water (SRW) pump breaker, number 152-1411, was in the adjoining cubicle. This is identical to and interchangeable with breaker 152-1410. Since the 13 SRW pump may be powered from the 14 or the 11 4Kv safety buses, removing one of its breakers would not disable the pump. Additionally, the No. 12 SRW pump was operable. After discussion with the shift supervisor, the technicians removed defective breaker 152-1410 and replaced it with 152-1411. Following a breaker and pump operational test, the 13 HPSI pump was declared operable and Unit 1 exited TS 3.0.3 at 2:35 p.m.

Followup troubleshooting on breaker 152-1410 revealed that the "close" coil armature was not fully resetting. It was binding with the spacer used between the coil plunger and the coil support bracket. Two spacers are used on the plunger, one on the front and one on the back. The center openings of the spacers are of different sizes, to match the plunger shape. The plunger was binding because the spacers were reversed; the spacer with the smaller center hole was installed on the large plunger end. An issue report was written to document and track the problem to resolution.

Breaker 152-1410 was repaired and restored to its original configuration on December 2. Breaker 152-1411 was also restored to its original location. The two breakers were retested satisfactorily. BG&E is investigating the history of this 4 Kv breaker to determine when the plunger spacers were reversed. In addition, they selected a representative sample of similar breakers for inspection on a not-to-interfere basis with operations to determine the extent of the problem. At the close of the inspection period, no similar breaker problems had been identified. The event was documented by Licensee Event Report 91-009.

The inspectors followed the breaker repair and reviewed the documentation of the problem. The interchangeability of the two breakers was verified by the inspectors. The inspectors had a question with the documentation of the work. In order to perform the work in a timely manner and within the constraints of the technical specification, the shift supervisor declared the breaker replacement to be emergent work. This allowed the paperwork to be generated concurrent with the maintenance. The maintenance activity is clearly logged in the shift supervisor's log and documented on a maintenance request and maintenance orders, but the inspectors could not find documentation that specifically identifies the activity as emergent work. The maintenance request and orders document the activity as priority 1 originally and as priority 2 subsequent to the breaker replacement. The inspectors discussed the documentation of emergent work with the technicians and with operations and electrical maintenance supervisors. An issue report was written to document the problem and to track clarification of the Calvert Cliffs instructions governing emergent work documentation. The inspectors consider the documentation question to be one of minor administrative importance. The Calvert Cliffs instructions governing emergent work appear to be adequate but could be improved with more specific guidance to the shift supervisor regarding documentation.

The coordination and control of the breaker swap was well handled by the shift supervisor and the electrical work supervisor on the scene. Good initiative was demonstrated to recognize the similar breakers and restore the 13 HPSI pump to operability to prevent an unnecessary plant transient. Their actions were deliberate and well considered, with due regard for safety.

c. Unit 1 Shutdown

On December 21, 1991, a Unit 1 shutdown was commenced from 60% power to allow repair of seat leakage past the No. 12B safety injection tank (SIT) outlet check valve. Leakage in excess of the surveillance limits was discovered on October 29, 1991, as discussed in NRC Inspection Report 50-317 & 50-318/91-24.

The shutdown decision followed unsuccessful attempts to flush the seat to remove O-ring debris in order to improve leakage. The measured leakage was 30.6 gallons per minute (gpm) and the maximum design limit was 33 gpm at power levels less than 80%. A test earlier in the day resulted in a 28.8 gpm leakrate. Due to the predicted leakage rate which was expected to be over the limit on the next leak test, BG&E management decided to shut down the unit and repair the valve. The inspectors were onsite for the testing and monitored BG&E's decision process. The inspectors concluded that the decision to shut down for repair demonstrated a good safety perspective.

Upon disassembly of the outlet check valve, BG&E found that the O-ring had been broken between the 10 and 2 o'clock positions at the top of the disc. BG&E reassembled the valve with a new O-ring. Based on historical results, they determined that there is reasonable assurance of satisfactory leak tightness until a permanent repair of the valve can be made during the spring 1992 refueling outage. Extensive measurements of the valve were taken so that alternative long-term repairs, such as seat/disc machining, can be done if a replacement valve is not available. Following system restoration, the valve showed no leakage during post maintenance testing. BG&E is continuing periodic testing and monitoring of pertubations of the valve.

During the unit shutdown, operators noted that the main turbine mechanical trip solenoid did not trip the mechanical trip valve when the master trip button was pushed. The button did trip the master trip solenoid valve which shut down the turbine. After the control room operators noted the failure of the mechanical trip valve to trip, an operator was sent to the local turbine gage board to initiate a manual mechanical trip. The manual action successfully tripped the mechanical trip valve.

Unit 1 has a General Electric main turbine with two redundant trip features, one mechanical and one electrical. All turbine trip signals, except the mechanical overspeed trip and the manual mechanical trip, are received at the master trip bus. The bus energizes, which in turn energizes the master trip relay. When this relay energizes, two redundant trip actions are initiated to shutdown the turbine: both master trip solenoid valve solenoids are deenergized, causing the master trip solenoid valve to move to the tripped position; and the mechanical trip solenoid energizes, causing the mechanical trip valve to move to the tripped position. These actions each accomplish depressurization of the emergency trip system hydraulic header and subsequent rapid closure of the turbine steam valves.

After shutdown, extensive electrical and mechanical troubleshooting was conducted on the mechanical trip system. No electrical circuit faults were found. During testing with no electro-hydraulic control (EHC) hydraulic system pressure, the mechanical trip solenoid plunger became stuck in the tripped position several times, but did not stick in the reset position. After several cycles, the plunger no longer became stuck, but reset smoothly. The linkage attached to the manual mechanical trip and the linkage actuated by the mechanical trip solenoid plunger were tested and moved freely with no sticking or binding. The EHC - hydraulic system was then started and the turbine was reset and tripped numerous times. The electrical and mechanical trip systems actuated properly each time to trip the turbine.

After evaluation of the troubleshooting data, BG&E concluded that the original failure was most likely caused by binding of the mechanical trip solenoid plunger. The trip features are tested as part of the turbine startup procedure. In this case, the last turbine startup had been on October 3. There is a weekly test of the overspeed trip feature, but it does not test the mechanical trip solenoid or the linkage actuated by the solenoid plunger. BG&E is investigating whether or not a test of this portion of the trip system could be done while the turbine is operating without undue risk of a turbine trip.

The solenoid in question is manufactured by Automatic Switch Company. The vendor technical manual recommends that it receive "an occasional internal inspection of the sliding surfaces," since it is not tightly sealed against the general environment. BG&E currently has no preventive maintenance requirement to perform that inspection, but is developing one as a result of their investigation into this issue. Other solenoids were inspected as a result of the troubleshooting, but no problems were found. The master trip solenoid valve solenoids are a different type that are tightly sealed.

The inspectors followed the troubleshooting efforts, reviewed the technical manual and operating procedures, and discussed the issue with systems engineering and operations personnel and management. The inspectors concluded that an appropriate level of attention was focused on the issue and that BG&E's actions were prudent. The safety significance of this event is considered to be low due to the redundant trip features which remained available, including the master trip solenoid valve electrical trip system, the mechanical overspeed trip, and the manual mechanical trip.

d. Emergency Air Lock Interlock Failure

At 8:30 a.m., on December 24, 1991, the Unit 1 containment personnel air lock inner door failed a routine performance of Surveillance Test Procedure (STP) M-171-1, "Personnel Air Lock (PAL) Gasket Seal Test." As a result, the outer door was closed and access to and from the containment was made via the emergency air lock (EAL) for ongoing corrective maintenance to the 12B safety injection tank discharge valves. At 3:30 p.m., personnel transiting the EAL noted that they were able to open both the inner and outer doors simultaneously and realized that the mechanical interlock was broken. They informed the control room. The shift supervisor stationed an interlock watch at the EAL and Unit 1 entered TS 3.6.1.3.a due to the EAL being inoperable. A four hour emergency notification was made to the NRC due to containmer integrity being violated for approximately one minute. As independently determined by th inspectors, however, no TS action statements were violated. The PAL inner door gasket was wiped down with demineralized water and adjusted. Following a satisfactory performance of STP M-171-1, the PAL was restored to service at 6:45 p.m.

Troubleshooting of the EAL found that the interlock locking plate set screws had come loose and the locking plate had slipped on the interlock shaft. The operating chain had also slipped one tooth on the sprocket. The locking plate and chain were realigned and the set screws were tightened. The interlock was tested satisfactorily and the EAL was restored to service at 5:30 a..n. on December 25, 1991.

The most likely cause of the interlock failure was preliminarily determined by BG&E to be the abnormally high usage of the EAL while the PAL was out of service. The determination of further corrective action is awaiting the completion of a systems engineering investigation into the event under problem deficiency report 91038.

The inspectors discussed the issue with operations management and mechanical maintenance personnel and reviewed the issue reports, work package, and technical manual for the air locks. The inspectors assess that the event is of low safety significance due to the short time the mechanical interlock was broken, the short time containment integrity was broken, the appropriate response by personnel discovering the issue, and the status of Unit 1 during the event (mode 4). Since the violation of containment integrity has potentially serious consequences, however, the inspectors are concerned with the simultaneous failure of both barriers that maintain integrity at the EAL: the EAL mechanical interlock and the administrative control of the operation of the EAL. The investigation into the mechanical and human factors contributing to the interlock failure and the violation of containment integrity has not yet been completed by BG&E and the NRC resident staff. As a result, the above concern is identified as an unresolved item (UNR 50-317 and 50-318/91-30-01).

c. Temporary Waiver of Compliance

Following the Unit 1 shutdown and cooldown on December 22, 1991, the motor operated outlet valve on the No. 12B safety injection tank (SIT), MOV-644, was manually closed to provide isolation for repairs to the No. 12B SIT check valve. Following repairs to the check valve, MOV-644 failed to reopen due to a bent stem. BG&E subsequently opened the valve by partially disassembling the operator. A modification was done to maintain the valve open by welding the stem to the yoke. This modification disabled the remote position indication. The unit was restarted on December 29, 1991, and operators began entering the containment every 12 hours to verify that the valve was open to satisfy technical specification surveillance requirement 4.5.1.a.2, which requires that each SIT outlet valve be verified open at least every 12 hours.

On December 31, 1991, BG&E requested and the NRC granted a Temporary Waiver of Compliance (TWOC) from the performance of surveillance requirement 4.5.1.a.2. BG&E also requested an amendment to modify this technical specification and delete the requirement to verify MOV-644 open. The TWOC will remain in effect until the NRC has completed its review for the technical specification amendment. The amendment will be in effect until the spring refueling outage.

The inspectors reviewed portions of BG&E's 50.59 evaluations regarding the modification, participated in a telephone conversation between BG&E and the NRC on December 30, 1991, and discussed the issue with NRC management and technical personnel. Considering that significant force was applied to bend the stem, the NRC had several questions regarding BG&E's assessment that the valve retained structural integrity and that the valve was, in fact, open. During subsequent conversations with the NRC on December 31, 1991, and in the letter requesting the TWOC, BG&E adequately addressed these concerns. Overall, the inspectors concluded that BG&E actions regarding this matter were adequate.

f. Inadvertent Unit 1 Auxiliary Feedwater Actuation

On December 29, 1991, at 10:29 a.m., with Unit 1 in Mode 3 (hot standby), an inadvertent auxiliary feedwater (AFW) actuation occurred while operators were attempting to reset sensor cabinet alarms. The No. 13 AFW pump started and injected for about 30 seconds before the actuation was reset and the pump secured. There were no noticeable changes in steam generator levels. The probable cause of the actuation was a static electric discharge. BG&E had previously identified that the actuation logic was susceptible to this type of electrical interference as documented in NRC Inspection Report 50-317 & 50-318/91-24. BG&E had previously taken action to require grounding straps when manipulating actuation logic components and has expanded this requirement to AFW sensor cabinets. BG&E response to the event was appropriate and the inspectors identified no further concerns.

g. Emergency Diesel Generator Trip

During performance of Surveillance Test Procedure (STP) O-7-1, "Engineered Safety Features Logic Test," at 11:43 p.m. on December 25, 1991, the 11 emergency diesel generator (EDG) tripped approximately 30 seconds after being paralleled to the 11 4Kv safety bus. The EDG had been loaded to 700 kw when the engine trip occurred, followed by an output breaker trip. Troubleshooting by BG&E immediately after the trip found no apparent cause. As an operability test, STP O-8-0, "11 Diesel Generator Test," was performed. The shift supervisor then declared the EDG operable. The following day, extensive troubleshooting by electrical maintenance and systems engineering failed to locate any abnormalities in the diesel or its control system. The EDG was then declared administratively out of service due to the inability to definitely determine the cause of the trip and BG&E concerns with the operability of the EDG based on only one performance of STP O-8-0.

In order to ensure the reliability of 11 EDG, three slow speed starts with one hour loaded runs were performed. These were followed by another performance of STP O-8-0. No problems were encountered. After evaluation of the accumulated troubleshooting and test data on December 27, 1991, by BG&E, 11 EDG was declared operable.

The resident inspectors discussed the issue with systems engineering management during and following the troubleshooting. Even though the cause of the trip was not determined during extensive troubleshooting, the reliability of the EDG is no longer considered to be in question. This is based on the satisfactory completion of five loaded runs of the EDG. The resident inspectors considered the level of investigation into the trip to be appropriate and agreed with the decision to declare the EDG operable.

h. <u>Unit 2 Manual Trip</u>

On January 2, 1992, at 10:22 p.m., Unit 2 was manually tripped from 92% power after the 26B feedwater heater tube side relief valve lifted and failed to reseat. Steam subsequently issuing from the turbine building floor drains resulted in low DC bus electrical grounds and a low main feed pump suction pressure alarm. Additionally, the No. 22 charging pump tripped which at the time was thought to be related the steam in the turbine building. The unit was maintained in mode 3 (hot standby) while the event was evaluated and repairs were made to the relief valve.

The inspectors reviewed the post trip review and attended the management briefing of the results. One discrepancy involved a computer clock function problem that prevented an accurate sequence of events printout and prevented assessing the trip time of the reactor protective trip breakers. The reactor trip breakers were later tested and the time was satisfactory. Also, the clock was reset on the computer to correct the clock problem. The cause of the DC system grounds was traced to moisture intrusion into the main feed pump low suction pressure alarm circuit. Electricians determined that the trip of the No. 22 charging pump was caused by a faulty low suction pressure trip switch and was not related to the steam in the turbine building. All other aspects of plant performance were as expected. At the briefing, the General Supervisor, Nuclear Plant Operations (GS-NPO) requested an engineering evaluation of the cause of the relief valve failure. At the conclusion of the meeting, permission to restart was granted by the GS-NPO.

The engineering evaluation indicated that over an extended period of time, the relief valve seat leakage had degraded the valve spring and probably changed the lift setpoint. The inspectors discussed this conclusion with the GS-NPO. The GS-NPO assessed that no other valves of this type were leaking and thus the source of degradation did not currently exist. However, the GS-NPO requested additional clarification from engineering regarding this issue. That clarification was not available as the inspection period ended. The inspectors walked down selected relief valves and determined that they had no indicated leakages, thus concluding that the current potential for degradation was minimal.

The inspectors discussed the causes of the DC system grounds and the potential effects of grounds on non-safety related equipment on safety related equipment. Two of the four DC busses, No. 11 and No. 21, have an automatic ground detection system and the remaining busses have a manual system. A "ground" will be indicated when resistance between either the positive or negative portion of the circuit and ground is less than 6000 ohms. This provides early indication of degraded conditions before any significant impact on system performance. For a short circuit to occur, there must be two grounds, one each on the positive and negative portions of the system. Also, protective fusing and fuse coordination is provided to isolate potential shorts to the affected component before impacting the bus. These design features and the priority placed on correcting indicated grounds minimizes the potential failure of safety related equipment as a result of a non-safety related ground.

Overall, the inspectors concluded that operator response to the steam leak was cautious and safety conscious. BG&E followup and corrective actions were appropriate.

2.3 Independent Safety Walkdown

a. ECCS Room Cooler Operability Verification

On December 8, 1991, routine surveillance testing identified degraded (slow) opening time for 2-SW-1573, the inlet supply valve for the No. 22 Emergency Core Cooling System (ECCS) room cooler. This valve is an air operated valve with air supplied via a solenoid valve. The room cooler provides a support function to ensure operability of the ECCS pumps located in that room.

BG&E placed administrative controls, via an operations temporary note, to maintain the valve open pending corrective action. The inspectors independently reviewed controlled drawings, inspected the valve, and discussed the system design with senior operator licensed personnel to assess if this valve would remain open during postulated events such as the loss of air or loss of electrical power. The inspectors concluded that the valve would remain open for these events thus the room cooler remained operable.

2.4 Operations Department Review

The inspectors reviewed the operations department structure and staffing and selected operations initiatives to assess their impact on operations performance. The review was performed via observations, discussions with personnel, and document reviews.

a. Operations Department Overview

The Superintendent - Nuclear Operations (S-NO) is responsible for all operations department activities and reports directly to the Plant General Manager. The General Supervisor - Nuclear Operations Support (GS-NOS) has oversight of operations support activities which include safety tagging, procedure development, and the operations maintenance coordination (OMC). The General Supervisor - Nuclear Plant Operations (GS-NPO) has oversight of the plant operating staff. The GS-NOS and the GS-NPO report to the SNO.

The GS-NOS has a staffing compliment of 44 personnel. Not all staff positions are filled and contractor support is used to perform some functions. While current support needs are being met, staffing increases are projected to meet future needs. The support organization has 10 senior reactor operators and 5 reactor operators. The staffing levels of the OMC function were recently increased to enhance prioritization, work coordination, and communication. This expansion formally implemented an earlier imitative to enhance outage coordination.

The GS-NPO has a staffing compliment of 124 personnel. There are five operating shifts on rotation each with four senior reactor operators (SRO's) and four reactor operators (RO's). There are also at least 12 non-licensed plant operators on each shift. Of the on shift SRO's, there are six qualified Shift Technical Advisors (STA's). These staffing levels exceed the minimum personnel requirements for TS 6.2.2.a. and the number of personnel required for safe shutdown from outside the control room. Several additional personnel including STA candidates have been hired during the current SALP period to increase shift staffing levels in the future.

The inspectors concluded that current staffing and operations department structure support safe operations and meet regulatory requirements.

b. Shift Supervisor's Office Relocation

In October 1991, the Shift Supervisor's (SS) office was relocated. Formerly the office was located outside the control room. The relocation moved the office within the control room to an elevated location. The new office gives the SS visual contact over most control room activities and ready access to the rest of the control room. Additionally, the office space has been increased allowing more workspace and storage. The inspectors concluded that the relocation improves SS oversight of control room activities and improves operator interface with the SS.

c. Operations Performance Assessment

Operations management monitors selected operations performance objectives to enable assessment and feedback regarding safety and quality performance. The objectives include operator performance elements such as the length of time between operator errors which result in inadvertent plant trips, inadvertent safety features actuations, and significant incidents. Significant incidents are defined as events caused by personnel error that would result in a potential impact to plant safety, a radiological event, an impact on personnel safety, an unexpected significant reduction in power, a significant cost for equipment replacement, and any activity that would degrade external perceptions of operations.

The measurement of these objectives indicates an increase in the length of time between events since April 1991. The inspectors also assessed that the recent events have a lower safety significance than previous events. Actions taken by BG&E in response to a violation identified in NRC Inspection Report 50-317 and 50-318/91-09 (NV4 50-317 and 50-318/91-09-01) regarding improper procedure implementation have been a significant factor in approximately doubling the time between operator caused events.

In responding to the Notice of Violation, BG&E committed to establish a pre-evolution briefing (pre-brief) process, improve guidance on communications, and enhance guidance regarding supervisory actions. The inspectors have observed several plant evolutions, tests, and pre-briefs where this guidance has been applied. The guidance was incorporated into CCI-140, "Conduct of Operations," which was reviewed by the inspectors. The inspectors concluded that the commitments have been effectively implemented, overall performance has improved, and the actions have addressed NRC concerns regarding this issue.

3.0 RADIOLOGICAL CONTROLS

During tours of the accessible plant areas, the inspectors observed the implementation of selected portions of the licensee's Radiological Controls Program. The utilization and compliance with special work permits (SWPs) were reviewed to ensure that detailed descriptions of radiological conditions were provided and that personnel adhered to SWP requirements. The inspectors observed that controls of access to various radiologically controlled areas and use of personnel monitors and frisking methods upon exit from these areas were adequate. Posting and control of radiation areas, contaminated areas and hot spots, and labelling and control of containers holding radioactive materials were verified to be in accordance with licensee procedures.

Health Physics technician control and monitoring of these activities were determined to be good. Overall, an acceptable level of performance was observed.

4.0 MAINTENANCE AND SURVEILLANCE

4.1 Maintenance Observation

The inspectors observed maintenance activities, interviewed personnel, and reviewed records to verify that work was conducted in accordance with approved procedures, technical specifications, and applicable industry codes and standards. The inspectors also verified that: redundant components were operable, administrative controls were followed, tagouts were adequate, personnel were qualified, correct replacement parts were used, radiological controls were proper, fire protection was adequate, quality control hold points were adequate and observed, adequate post-maintenance testing was performed, and independent verification requirements were implemented. The inspectors independently verified that selected equipment was properly returned to service.

Outstanding work requests were reviewed to ensure that the licensee assigned appropriate priority to safety-related maintenance. The inspectors observed/reviewed portions of the following maintenance activities.

a. Replace No. 21 Auxiliary Building Supply Fan Belts

This maintenance replaced worn fan belts on the No. 21 auxiliary building supply fan. This fan is non-safety related and provides supply air for normal building ventilation. The inspectors observed safe work practices by the maintenance personnel including stopping the job to secure the fan which began to slowly rotate due to windy conditions.

The inspectors noted, however, that the maintenance document contained a procedure, MMWP-IV-02, Rev. 1 "Inspection and Replacement of Belts" marked "information only." The inspectors expressed concern to maintenance department supervision that work should be performed only per controlled documents as required by CCI-101, "Calvert Cliffs Implementing Procedure Development and Control," section 6.16. Since this procedural requirement is applicable to both safety and non-safety related work, the inspectors independently verified that the procedure in the field was the correct revision and was up to date for the work.

The Mechanical Maintenance General Supervisor issued additional guidance via a memorandum to supervisory personnel regarding the expectations for controlled procedure use. An issue report was also initiated to document the problem. The inspectors determined that these actions were appropriate.

The inspectors concluded that the problem in this case was administrative in nature, was the only observed instance, and was of low safety significance. However, this observation is an indicator that continued management diligence is needed to assure proper procedures are used to perform maintenance activities.

b. No. 21 Pressurizer Proportional Heater Breaker Repair

The inspectors observed portions of the testing, disassembly, and reassembly of the No. 21 pressurizer proportional heater circuit breaker. The Westinghouse DS-206 type circuit breaker was undergoing repair to replace worn pivot arms. The inspectors verified that selected portions of the procedures were consistent with the technical manual. The work observed was performed safely and in accordance with the procedures.

c. Cable Installation For Modification

The inspectors observed portions of the work to install conduit and pull cable to support facility change request (FCR) 90-91. The FCR, when complete, will eliminate unneeded emergency diesel generator starts during engineered safety features actuation (ESFAS) logic testing. Conduit and cables were installed between the safety related switchgear rooms on the 27 foot and 45 foot elevations of both units and the ESFAS logic cabinets in the cable spreading rooms.

The installation involved passing through several fire barriers. The inspectors noted that selected fire barrier requirements were satisfied. The inspectors also walked down the installation and observed the condition of selected fire penetrations that had been disturbed. These penetrations appeared to be restored as required. One temporary barrier was observed and the penetration appeared to be properly filled with a fire blocking material.

The inspectors observed portions of the cable pulls and discussed cable pulling requirements with workers and a quality verification inspector. These personnel were aware of limits on the cable tension (60 lb). Actions were taken during the cable pulls to minimize stress by the use of approved lubricants.

Overall, the inspectors concluded that the work was performed in accordance with the procedure and requirements.

4.2 Surveillance Observation

The inspectors witnessed selected surveillance tests to determine whether properly approved procedures were in use, technical specification frequency and action statement requirements were satisfied, necessary equipment tagging was performed, test instrumentation was in calibration and properly used, testing was performed by qualified personnel, and test results satisfied acceptance criteria or were properly dispositioned. Portions of the following activities and surveillance test procedures (STP) were reviewed.

a. STP M-212C-1, "RPS Functional Test, Channel C"

The inspectors observed portions of the procedure, including pre-briefing of the test personnel by their supervisor, on November 19, 1991. An overall acceptable level of knowledge and performance were observed of the test personnel.

b. Flush and Seat Leak Test of No. 12B Safety Injection Tank Check Valve

The inspectors observed the seat leak test of the No. 12B safety injection tank (SIT) outlet check valve. The flush and test were accomplished per instructions in operating instruction 3A, "Safety Injection and Containment Spray System," in an attempt to flush the seat to remove O-ring debris in order to improve the leakrate. Unit 1 power was reduced to 60% and two flushes were performed with a final measured leakage of 30.6 gallons per minute (gpm). The maximum design limit was 33 gpm at power levels less than 80%. A test earlier in the day resulted in a 28.8 gpm leakrate. Due to the predicted leakage rate which was expected to be over the limit on the next leak test, BG&E management decided to shut down the unit and repair the valve.

The inspectors assessed that the testing was well briefed, properly controlled, and well performed. The system engineer was present for the entire evolution. The inspectors also reviewed the test methodology and concluded that it was appropriate.

c. STP 0-5-1, "Auxiliary Feedwater System Test"

The inspectors observed portions of this test and reviewed the completed procedure for administrative detail. The inspectors noted that this test satisfies technical specification requirement 4.7.1.2.a. The test also collected data for inservice testing. An acceptable level of performance was observed.

5.0 EMERGENCY PREPAREDNESS

The inspectors toured the onsite emergency response facilities to verify that these facilities were in an adequate state of readiness for event response. The inspectors discussed program implementation with the applicable personnel. The resident inspectors identified no deficiencies in this area.

6.0 SECURITY

During routine inspection tours, the inspectors observed implementation of portions of the security plan. Areas observed included access point search equipment operation, condition of physical barriers, site access control, security force staffing, and response to system alarms and degraded conditions. These areas of program implementation were determined to be adequate. No unacceptable conditions were identified.

7.0 ENGINEERING AND TECHNICAL SUPPORT

The inspector reviewed selected design changes and modifications made to the facility which the licensee determined did not involve unreviewed safety questions and did not require prior NRC approval as described by 10 CFR 50.59. Particular attention was given to safety evaluations, Plant Operations Safety Review Committee (POSRC) approval, procedural controls, post-modification testing, procedure changes resulting from this modification, operator training, and UFSAR and drawing revisions. The following activities were reviewed:

7.1 Safety Review for No. 12B Safety Injection Tank Leakage

The inspectors reviewed the 50.59 evaluation and attended the POSRC meeting regarding degraded leakage on the No. 12B safety injection tank (SIT) inlet check valve. This evaluation was performed to allow operational leakage limits to be increased from 26.2 gpm to 28 gpm for 100% power operation and from 31 gpm to 33 gpm at power levels less than 80%. The increased leakage rates were based on a smaller calculated instrument error in the SIT level instrumentation than had been used in the previous 50.59 evaluation. The inspectors concluded that the appropriate safety concerns were addressed in the evaluation.

7.2 Evaluation of Operation of Two Non-Radioactive Systems While Contaminated

The inspectors reviewed BG&E actions in response to concerns regarding the operation of two non-radioactive systems while contaminated. At the time this concern was identified, there was no current safety evaluation to determine if operation constituted an unreviewed safety question. The two systems in question were the auxiliary boilers and the nitrogen system.

NRC Bulletin 80-10, states that operation of a non-radioactive system following contamination is acceptable as long as operation neither constitutes an unreviewed safety question nor requires a change to the technical specifications (i.e., releases are within technical specification limits). However, these systems were operated while contaminated without a safety evaluation. This concern was identified in NRC Inspection Report 50-317 and 50-318/89-23 as an unresolved item (UNR 50-317 and 50-318/89-23-01) pending NRC review of the 50.59 safety evaluation and assessment of operation of the systems without a safety evaluation.

The safety evaluations were initially prepared in January 1990 and subsequently revised with the most recent revision approved in January 1991. The evaluations concluded that there was no unreviewed safety question and a change to the technical specifications was not required.

The inspectors reviewed the final safety evaluations including system descriptions, routine chemistry surveillance procedures, and dose projection calculation methodology using the worst accident scenario for the systems. The inspectors also discussed the safety evaluation conclusions with cognizant BG&E personnel. The inspectors determined that the evaluations were sound and that the conclusions were appropriate. The inspectors noted that BG&E has implemented surveillance programs to sample the systems weekly and perform gamma isotopic analysis. Additionally the inspectors discussed the modification of the Offsite Dose Calculation Manual (ODCM) to address concerns with the operation of contaminated non-radioactive systems. BG&E agreed to include in the ODCM: (1) a discussion of unmonitored releases, (2) identification of the analyzed pathways, (3) relation of the surveillances of known pathways to the chemistry procedures, (4) direction that other pathways would be evaluated if required, and (5) identification of the basis of the criteria for evaluation of non-radioactive contaminated systems.

The inspectors assessed the operation of the systems while contaminated prior to a safety evaluation and concluded that no further action was needed. This is based on NRC's recognition in Bulletin 80-10 that operation is acceptable as long as it does not constitute an unreviewed safety question or require a change to the technical specifications (i.e., releases are within technical specification limits). Additionally, safety significance was minimal based on the safety evaluations which concluded that operation was acceptable, actions were taken at the time the problem was identified to minimize contamination, programs are in place to monitor these and other systems, and the evaluation criteria will be incorporated into the ODCM.

The inspectors concluded that these actions have appropriately addressed concerns in this matter and no further concerns were identified.

7.3 Main Vent Radiation Monitoring System Assessment

The inspectors performed a walkdown of the main vent radiation monitoring (RMS) system on both units. The inspectors reviewed the technical specification operability requirements, descriptions in the Final Safety Analysis Report (FSAR), operating instructions (OI's), and discussed the system with cognizant personnel. The system is designed to continuously sample main vent effluent and provide data, indication, and alarm functions regarding main vent effluent. A 10 cubic foot per minute (CFM) pump provides the sample flow to a moving paper particulate monitor (RE-5414) and then to a gaseous monitor (RE-5415). On branch lines there is a tritium sampling rig and a 1 CFM "portable" sample pump and filter assembly.

The inspectors noted during the review that Table 1 of OI-35 "Radiation Monitoring System" indicated that the portable sample assembly satisfied the monitoring requirements of TS 3.3.3.9 for particulate effluent monitoring. However, the portable sampling assembly is not described in FSAR section 11. The inspectors questioned the basis for the use of the portable sampling assembly and the design basis of this assembly. BG&E indicated that similar concerns had already been raised and were documented in program deficiency report No. 91023.

BG&E reviewed the concerns and discussed them with the inspectors. BG&E stated that the technical specifications associated with the monitor, the ODCM, and OI-35 were consistent and were developed with consideration of the portable sampling assembly. The resident inspectors and a specialist inspection from the Division of Radiation Safety and Safeguards determined that the use of the portable assembly to satisfy the technical specification requirements was appropriate based on the historical development of the radiological technical specifications and the ODCM and the fact that a "sampler" is indicated in the specification rather than a monitor. BG&E indicated that the FSAR needed to be updated to reflect the use of the portable assembly. A 50.59 evaluation will be performed to assess the design of the portable assembly. This evaluation is expected to be complete in February 1992.

The inspectors also questioned the operability of the portable sampler during times that the main (10 CFM) pump is out of service because flow through the sample lines with only the portable sample pump will be reduced to 1 CFM. With the reduced flow there is a potential for plateout of the particulate and iodine components of the effluent. BG&E agreed to fully assess this concern in its 50.59 evaluation. Currently BG&E considers the sampler operable because the potential for plateout is minimized since the particle size is small, the sample line geometry is simple with minimal 90 degree turns, the iodine is generally found in a molecular form and is less reactive than elemental iodine, and the 10 CFM pump is normally running to support gaseous monitoring.

The inspectors concluded that BG&E actions to evaluate the portable sampler and update the FSAR sufficiently address the concerns. The concerns will be tracked and documented in response to the program deficiency report.

8.0 SAFETY ASSESSMENT AND QUALITY VERIFICATION

8.1 Plant Operations and Safety Review Committee

The inspector attended several Plant Operations and Safety Review Committee (POSRC) meetings. TS 6.5 requirements for required member attendance were verified. The meeting agendas included procedural changes, proposed changes to the TS, Facility Change Requests, and minutes from previous meetings. Items for which adequate review time was not available were postponed to allow committee members time for further review and comment. Overall, the level of review and member participation was adequate in fulfilling the POSRC responsibilities.

During a POSRC meeting, the inspectors noted that required presentations of some surveillance test results were not performed within the time constraints of CCI-104, "Surveillance Test Program." The inspectors discussed this observation with the POSRC Chairman who in turn wrote an issue report to document the problem. The time constraints were self imposed by BG&E to ensure timely provision of information to the POSRC. The scope of the problem is administrative, appears to be limited in nature, and is due to a recent high workload. An overall acceptable level of performance was observed.

9.0 FOLLOWUP 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 inspector determined that corrective actions would prevent recurrence. Those items for which additional licensee action was warranted remained open. The following items were reviewed.

9.1 Closed (UNR 50-317/318-89-23-01): Evaluation of Operation of Two Non-Radioactive Systems While Contaminated Without a Safety Evaluation

This issue involved the operation of contaminated, non-radioactive systems. This issue was inspected as indicated in section 7.2 of this report and is considered closed.

9.2 Closed (NV4 50-317/318-91-09-01): Reductions in Operator Events

This issue involved the improper implementation of procedures by operators which resulted in a containment spray event and an inadvertent engineering safety features actuation. This issue was inspected as indicated in section 2.4 of this report and is considered closed.

10.0 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.

On December 3, 1991, Mr. L. Gibbs, General Supervisor - Calvert Cliffs Security Operations, and other members of the security organization staff briefed the Region 1 staff at King of Prussia, Pennsylvania, regarding progress and plans of the plant's new Nuclear Security Facility. In that the meeting dealt almost exclusively with details of the security program, eg., detection system upgrades, details of assessment systems, and compensatory measures to be implemented during transition, the meeting was closed to the public to prevent disclosure of Safeguards Information defined within 10 CFR 73.21.

On December 20, 1991, Mr. F. Sturz, of the NRC (NMSS), toured the independent spent fuel storage facility and met with BG&E management to discuss licensing issues.

On December 24, 1991, Dr. T. Murley, Director, NRR, toured the site and met with the resident inspectors and with Mr. G. Creel, Vice President - Nuclear Energy Division.

On December 30, 1991, Mr. C. Poindexter, Vice Chairman of the Board, and other members of the management of Calvert Cliffs briefed the Region 1 staff at King of Prussia. The subject areas discussed included recent plant performance, results of the December IPAT, and BG&E plans and allocated resources for the plant in 1992.

10.1 Preliminary Inspection Findings

One unresolved item was identified for followup on the failure of the EAL interlock (UNR 50-317 and 50-318/91-30-01). This issue is discussed in Section 2.2(d).

10.2 Attendance at Management Meetings Conducted by Region Based Inspectors

Date	Subject	Inspection Report No.	Reporting Inspector
12/13/91	IPAT	50-317/91-82 50-318/91-82	J. Lyash
12/20/91	Effluent Controls	50-317/91-31 50-318/91-31	J. Jang