**U.S. NUCLEAR REGULATORY COMMISSION**
**REGION I**

| | |
|---|---|
| License Nos. | DPR-53/DPR-69 |
| Report Nos. | 50-317/96-02; 50-318/96-02 |
| Licensee: | Baltimore Gas and Electric Company<br>Post Office Box 1475<br>Baltimore, Maryland 21203 |
| Facility: | Calvert Cliffs Nuclear Power Plant, Units 1 and 2 |
| Location: | Lusby, Maryland |
| Dates: | February 11, 1996, through March 30, 1996 |
| Inspectors: | J. Scott Stewart, Senior Resident Inspector<br>Carl F. Lyon, Resident Inspector<br>Henry K. Lathrop, Resident Inspector<br>Leonard S. Cheung, Senior Reactor Engineer, DRS<br>Jason Jang, Ph.D., Senior Radiation Specialist, DRS |
| Approved by: | Lawrence T. Doerflein, Chief<br>Reactor Projects Branch 1<br>Division of Reactor Projects |

9605060339 960429
PDR ADOCK 05000317
Q PDR

## EXECUTIVE SUMMARY

### Calvert Cliffs Nuclear Power Plant, Units 1 and 2
### Inspection Report Nos. 50-317/96-02 and 50-318/96-02

This integrated inspection report includes aspects of BGE operations, maintenance, engineering, and plant support. The report covers a seven week period of resident inspection; in addition, it includes the results of announced inspections by a senior radiation specialist and a senior reactor engineer.

<u>Plant Operations</u>

- During a Unit 2 forced outage, nuclear safety was enhanced using centrally coordinated outage management and detailed operations oversight of plant configuration. Plant operations and maintenance implementation and oversight of outage activities were excellent, and the unit was returned to power operation on March 3, 1996, in a safe and timely manner.

- Following service water system maintenance, operators missed a procedure step, resulting in a service water valve was being left in the wrong position. The problem was self-identified when action by operators to increase steam generator blowdown flow resulted in a high temperature alarm. BGE took corrective actions and the issue was considered a Non-Cited Violation, consistent with Section VII of the NRC Enforcement Policy.

<u>Maintenance</u>

- A loss of offsite power reactor trip occurred on Unit 2 during troubleshooting in the switchyard. The root cause of the trip involved poor work practices by the System Operation and Maintenance Department (SOMD) that included uncontrolled configuration changes and inadequate communications with plant operators. BGE management oversight of the switchyard troubleshooting was also weak. BGE identified that corrective actions for a 1993 reactor trip that involved similar circumstances were ineffective.

- The Calvert Cliffs electrical maintenance and operations staff used poor judgement in not designating switchyard troubleshooting as trip sensitive. This judgement demonstrated a weakness in the implementation of the Calvert Cliffs trip prevention program. The switchyard area was listed as a trip risk area in the trip prevention program procedures, and entrance to the switchyard was prominently posted as a trip sensitive area. However, during troubleshooting, the trip prevention precautions specified by Calvert Cliffs procedures, including adequate direction and understanding of the task by all personnel involved, use of a detailed work plan, control of configuration changes, and General Supervisor-Nuclear Plant Operations concurrence to the troubleshooting plan, were not done.

- Poor work practices by maintenance electricians caused the loss of a 480V Motor Control Center (MCC). As the electricians were pulling cable leads through a cubicle panel, one of the leads shorted to energized MCC bus bars causing smoke and equipment damage. The MCC feeder breaker opened on the fault. In another occurrence, instrument technicians installing a test lead from a recorder inadvertently grounded the lead and introduced a step change decrease in pressurizer pressure indication causing all pressurizer backup heaters to energize. Corrective actions by BGE for the two occurrences were appropriate.

- The inspectors noted that the BGE personnel demonstrated an appropriate regard for nuclear safety, as indicated by controls instituted to ensure containment integrity during fuel moves and periods of reduced reactor water inventories.

- A weak surveillance procedure contributed to the inadvertent opening of a pressurizer power operated relief valve (PORV). The PORV block valve was shut during the test. The inspectors considered the corrective actions taken by BGE to be appropriate. The issue was considered a Non-Cited Violation, consistent with Section VII of the NRC Enforcement Policy.

- The inspectors questioned the prudence of conducting switchyard troubleshooting coincident with the on-line repair of a turbine driven auxiliary feedwater pump and service water work that would have disabled an emergency diesel generator. In response to the inspector concerns, BGE halted switchyard troubleshooting until safety equipment was in full readiness. BGE also conducted an evaluation of maintenance sequencing and initiated actions to improve risk management during maintenance. The inspector considered the BGE actions to include human factors and troubleshooting in maintenance risk evaluation to be an appropriate upgrade to the Calvert Cliffs risk assessment program.

<u>Engineering</u>

- BGE responded appropriately following the identification of the cylinder liner scuffing problems for the 1A and OC diesel generators in January, 1996. Extensive effort was provided by BGE management to promptly identify the failure root causes and implement appropriate corrective actions. The problem was resolved within a tight operation schedule and the impact of this problem on refueling outage preparations was minimized. The BGE root cause analysis team properly integrated and validated the root cause findings from various consultants and vendors. The root cause analysis reports were of good quality. A structured decision-making methodology was frequently applied during the analysis process. The methodology used by BGE to select a new lubricating oil was logical and was based on thorough engineering evaluation.

- The corrective actions taken by BGE to resolve an electrical distribution system functional inspection (EDSFI) unresolved item (92-80-09) may have been inadequate. The available air-flow used to manually cool (with one portable fan) the 27-foot elevation emergency switchgear room (ESR) during an emergency condition was never validated to confirm its adequacy. BGE later increased the available air-flow by using two portable fans, and plans to conduct a test to determine if sufficient air flow was ever available for manual cooling of the ESR. This item was unresolved pending completion of the test and review of the results.

Plant Support

- BGE maintained excellent radioactive liquid and gaseous effluent control programs. The Chemistry staff demonstrated excellent knowledge and ability in the implementation of the effluent control programs. The responsible individual for radiation monitoring systems and air cleaning systems demonstrated good knowledge of the equipment and system capability.

- BGE management support to Effluent ALARA (As Low as Reasonably Achievable) was an excellent commitment to minimize radioactivity releases to the environment.

## TABLE OF CONTENTS



### ATTACHMENT

## Report Details

Summary of Plant Status

Unit 1 began the period at full power. On March 15, 1996, BGE placed the unit in a power and temperature coastdown and on March 29, the unit was shutdown for refueling outage number 12.

Unit 2 began the period at full power. On February 27, Unit 2 tripped due to loss of reactor coolant pumps that resulted when the 500 kV "red" bus was deenergized. At 5:42 p.m., BGE declared an Unusual Event due to the partial loss of offsite power. The unit was stabilized in Mode 3 (hot standby), the electrical lineup was restored, and the Unusual Event was ended at 8:15 p.m. The unit was subsequently cooled down to Mode 5 (cold shutdown) to repair a leaking check valve in the steam generator blowdown system. Following investigation of the trip and completion of forced outage maintenance, BGE returned the unit to full power on March 6.

## I. Operations

### O1 Conduct of Operations [1]

O1.1 General Comments (71707)

Using Inspection Procedure 71707, the inspectors observed plant operation and verified that the facility was operated safely and in accordance with licensee procedures and regulatory requirements. During the inspection period, the inspectors provided onsite coverage and followed unplanned events. Specific events and noteworthy observations are detailed in the sections below.

O1.2 Unit 2 Automatic Reactor Trip Due to Loss of 500 kV "Red" Bus

a. Inspection Scope (93702)

At 5:08 p.m., while troubleshooting in the 500 kV switchyard was in progress, Unit 2 experienced a reactor trip on loss of reactor coolant flow due to a partial loss of offsite power that occurred when the 500 kV "red" bus was de-energized. The loss of the red bus deenergized plant transformer P-13000-2 which caused the loss of the Unit 2 13kV service buses, and 4kV buses 22, 23, 24, 25, and 26. Safety related bus 21 remained energized because it was powered from Unit 1. Except for the loss of safety related bus 14, which is powered from Unit 2, Unit 1 was not affected and remained at full power during the event.

[1] Topical headings such as O1, M1, etc., are used in accordance with the NRC standardized reactor inspection report outline found in MC 0610. Individual reports are not expected to address all outline topics.

b. Observations and Findings

At 11:36 a.m. on February 27, 1996, with both units at full power, 500kV circuit breakers 552-41 and 552-43 began cycling open and shut. Reactor operators responded by putting the respective breaker control switches in pull-to-lock, which disconnected 500kV high line 5052 from the switchyard. The BGE System Operation and Maintenance Department (SOMD) was informed and responded to the 500kV switchyard, where troubleshooting was initiated. The early actions included opening disconnects to isolate the open breakers and investigating for obvious causes of the circuit breaker cycling.

At 5:08 p.m., with troubleshooting in progress, the red bus was deenergized and the Unit 2 reactor trip occurred. The operators responded to the reactor trip by performing the actions of emergency operating procedure, EOP-0, "Reactor Trip." Subsequently, operators transitioned to EOP-2, "Loss of Offsite Power," and at 5:42 p.m., BGE declared an Unusual Event as specified in the Calvert Cliffs Emergency Action Guidelines. The reactor was stabilized using natural circulation for primary heat transfer, and auxiliary feedwater and the atmospheric dump valves for secondary heat removal. At 8:15 p.m., with offsite power restored, the Unusual Event was ended. The operators transitioned to Operating Procedure, OP-4, "Plant Shutdown from Power Operation to Hot Standby," and maintained the reactor in hot standby. There were no significant equipment malfunctions or complications during the reactor trip and operator response.

Following the event on February 27, BGE management established a Significant Incident Finding Team (SIFT) to review the trip, determine the root cause, and formulate corrective action recommendations to prevent recurrence. As part of the SIFT charter all equipment that was called upon to function during the trip that may have malfunctioned was quarantined, subject to release by the SIFT Team Leader. Finally, the operations department was directed to maintain Unit 2 in hot standby (or Modes 4 or 5) until the SIFT determined the root cause and established preliminary corrective actions.

The SIFT completed the initial phase of their investigation and made a report to the Plant Operations Safety Review Committee on March 2, 1996. The root cause was determined to be poor work practices during the troubleshooting activities in the switchyard. The specific sequence that caused the loss of offsite power for Unit 2 included the trip of switchyard breakers 41 and 43 at 11:36 a.m., followed by troubleshooting that included removal of control power links for breaker 41, and the test closing of breaker 41. This combination actuated the "Breaker Failure Initiating Trip Bus," which in turn actuated a stuck breaker protection timer, which after an eight cycle delay, activated and opened switchyard breakers 552-21, 552-61, and the respective 13kV breakers to isolate power to Unit 2. The stuck breaker protection accomplished isolation of the faulted breaker 41 because breaker 41 was shut, the initial unidentified fault remained, and removal of the control power links prevented automatic opening of breaker 41.

In a January 1996 agreement between SOMD and Calvert Cliffs, SOMD maintained ownership of all 500 kV switchyard equipment and support systems. The agreement stated that SOMD would provide qualified personnel to perform work in the switchyard and that any interface with plant operations was to be based on the nature of the work performed and at the discretion of Calvert Cliffs electrical maintenance supervision. A subpart of the agreement stated that the 500 kV switchyard was a reactor trip sensitive area and that special precautions such as a trip prevention checklist should be used to heighten the awareness of workers in the switchyard to trip sensitivity. The switchyard access door and switchyard breaker control panels were prominently posted as "Trip Sensitive Areas."

Following the trip of 500kV breakers 552-41 and 552-43, and in accordance with SOMD procedures, the bulk power operator requested SOMD personnel at Calvert Cliffs to open 500kV disconnects 589-41A, 589-41B, and 589-43A and 589-43B, to electrically isolate the open breakers. Initial troubleshooting by SOMD included inspecting control circuits for the open breakers to identify trip targets which would be locked in if certain protective devices had actuated. No targets were identified. Concurrent with the initial SOMD efforts, Calvert Cliffs electrical maintenance personnel prepared a troubleshooting form in accordance with maintenance procedure MN-1-110, to document breaker circuit configuration during the troubleshooting. The troubleshooting form erroneously stated that the circuit breakers were electrically isolated and that the worst potential consequence of the troubleshooting activity would be the effect on other switchyard components if the wrong component was worked.

The troubleshooting form was designated Risk Level 3 for equipment that should not present a risk of causing an undesirable plant transient or reportable event. Risk Level 3 was assigned to the effort by electrical maintenance supervisors and concurred with by operations supervisors even though the switchyard area was defined as a trip sensitive area under the Calvert Cliffs Trip Prevention Program. Following the trip, electrical and operations supervisors informed the inspectors that because the 500kV disconnects had been opened, the proper level of trip risk was not considered in preparation of the troubleshooting form.

The work controls specified in the troubleshooting form were not followed when SOMD personnel changed switchyard component configuration without informing the Calvert Cliffs electrician who was monitoring the troubleshooting and maintaining the record. Among the troubleshooting activities not controlled using the procedural requirements of MN-1-110 were removal of the fuse links for circuit breaker 41 control circuit and the shutting of breaker 41, the combination of events which actuated the stuck breaker protection.

In a June 10, 1993 loss of offsite power event at Calvert Cliffs, during switchyard work, a flashover relay for 500 kV breaker 552-61 was inadvertently activated which isolated the red bus (See LER 50-317/318 93-003). A contributing factor in the June 10 trip was an uncontrolled change in 500 kV system configuration made when SOMD workers in the switchyard opened deenergized breaker 552-61 and enabled the flashover relay. At that time, the control circuit configuration change was not evaluated for trip potential and an inadvertent trip of the red bus resulted when the flashover relay was inadvertently actuated.

In response to the February 27, 1996 event, the Calvert Cliffs Plant General Manager established the following interim switchyard work controls:

1) The designation of the switchyard as a trip sensitive area was reemphasized. Control room notification was required prior to entry into the switchyard or the switchyard house.

2) Plant Engineering Section would be contacted during the work planning for switchyard maintenance. Plant engineering staff were required to assist with the assessment of trip risk and contingency planning for all maintenance in the switchyard.

3) Control room briefings were to be done by SOMD and plant engineering personnel prior to starting switchyard maintenance.

4) All troubleshooting was required to be conducted using formal procedures. Calvert Cliffs management review of troubleshooting plans was required prior to work.

5) A system engineer was designated the site sponsor for SOMD work in the switchyard.

Using a formal troubleshooting plan, Calvert Cliffs engineering and SOMD personnel identified the initial fault that caused 500 kV breakers 552-41 and 552-43 to trip. The problem was identified as an intermittent fault in a breaker failure auxiliary relay in the common control circuit for breakers 41 and 43. On March 2, the faulty relay was replaced, and the 500 kV transmission line was returned to service without additional problems. At the end of the inspection period, BGE submitted LER 50-318/96-001, "Automatic Plant Trip Due to Partial Loss of Offsite Power."

c. <u>Conclusions</u>

The root cause of the loss of offsite power reactor trip involved poor work practices by the system operating and maintenance group (SOMD) that included uncontrolled configuration changes and inadequate communications with plant operators. BGE management oversight of the switchyard troubleshooting was also weak in that quality standards were not specified for the work. BGE identified that corrective actions for a 1993 reactor trip that involved similar circumstances were ineffective.

The inspectors noted the switchyard was not a system in the BGE quality assurance program. Nonetheless, the inspectors determined the Calvert Cliffs electrical maintenance and operations staff used poor judgement in not designating the switchyard troubleshooting as trip sensitive. This judgement demonstrated a weakness in the implementation of the Calvert Cliffs trip prevention program. The switchyard area was listed as a trip risk area in the trip prevention program procedures and entrance to the switchyard was prominently posted as a trip sensitive area. Even so, the trip prevention precautions required by Calvert Cliffs procedure MN-1-110, including adequate direction and understanding of the task by all personnel involved in troubleshooting, use of a detailed work plan, control of configuration changes, and General Supervisor-Nuclear Plant Operations concurrence to the troubleshooting plan, were not included in the troubleshooting plan. BGE management acknowledged these weaknesses.

O1.3 Post Trip Activities

After the reactor trip and plant stabilization, BGE conducted maintenance in accordance with a preplanned forced outage plan. Included in the plan was a routine containment inspection wherein a steam leak on the 21 steam generator surface blowdown line was identified. Evaluation of the steam leak and an increased containment sump pumpdown frequency resulted in a plant management decision to take the unit to cold shutdown (Mode 5) for leak repair. Unit 2 entered Mode 5 on March 1, 1996 and the steam generator blowdown leak was repaired by replacing a check valve that had developed a cap gasket leak.

A quality verification audit of SOMD work practices in the switchyard was begun. On March 5, during troubleshooting of a 500 kV disconnect problem, Calvert Cliffs personnel observed SOMD personnel cleaning a component with a flammable solvent, and a small fire occurred when the solvent contacted energized electrical components. The fire caused no component damage and burned out in a number of seconds. Work in the switchyard was stopped by Calvert Cliffs management until the occurrence was reviewed and the cause determined. The quality verification audit identified a number of weak work practices, including work without a technical manual or procedural guidance, use of maintenance and test equipment without calibration stickers, poor foreign materials control practices, and a number of personnel safety issues. As part of the overall post-trip corrective actions, Calvert Cliffs management intended to compile the work practice weaknesses and review the issues with SOMD management.

During the Unit 2 forced outage, nuclear safety was maintained using preplanned essential equipment availability controls, centrally controlled outage management, and detailed operations oversight of plant configuration. Plant operations and maintenance implementation and oversight of outage activities were excellent, and the unit was returned to power operation on March 3, 1996, in both a safe and timely manner.

01.4 Service Water Valve Left in Wrong Position

On March 20, 1996, the 21 service water heat exchanger was removed from service for planned tube cleaning and related maintenance. Following completion of the work on March 22, control room operators completed steps in Operating Instruction 15, "Service Water System," to restore the valve lineup. During the restoration, a step was missed and valve 2-SRW-640, the 22 blowdown recovery heat exchanger service water inlet valve, was inadvertently left in the shut position. The problem was identified when operators raised steam generator blowdown flow and received a high blowdown temperature condition due to the lack of service water cooling.

Following receipt of the high temperature condition, the plant operators conducted an investigation and found the service water valve in the shut position. Further review by the operators determined that the operating procedure step was missed during the valve lineup restoration due to poor communications between the control room operator and the auxiliary building operator. Following review of the event, BGE established the following corrective actions:

1) The involved control room operator was counseled on procedure adherence and proper communication expectations.

2) The event was reviewed with the involved operating crew by the shift supervisor and a synopsis of the event was provided to all crews as a reminder of communication and procedure adherence expectations.

3) Management expectations for procedure adherence and effective communications were reviewed and discussed with all operating crews during safety meetings conducted after the event.

The inspectors found the corrective actions taken by BGE to be appropriate to the event. The failure to follow plant procedures in ensuring system configuration was identified by BGE and corrective actions were taken. The issue was considered a Non-Cited Violation, consistent with Section VII of the NRC Enforcement Policy.

**07 Quality Assurance in Operations**

07.1 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. During a meeting on February 28, the POSRC received an presentation from diesel generator project personnel on the tie-in of the new emergency diesel generators during the upcoming Unit 1 refueling outage. The committee concluded that due regard was being paid to the nuclear safety of both units and that adequate compensatory measures would be in place during the higher risk phases of the tie-in. On March 2, the POSRC reviewed the preliminary root cause evaluation associated with the February 27 reactor trip. In both cases, the committee evaluated the events in detail and reached a consensus position regarding plant safety. Overall, the level of review and member participation was satisfactory in fulfilling the POSRC responsibilities.

## II. Maintenance

### M1 Conduct of Maintenance

#### M1.1 Routine Maintenance Observations

Using Inspection Procedures 62703 and 61726, the inspectors observed the conduct of maintenance and surveillance testing on systems and components important to safety. The inspectors also reviewed selected maintenance activities to assure that the work was performed safely and in accordance with proper procedures. The inspectors noted that an appropriate level of supervisory attention was given to the work depending on its priority and difficulty. Maintenance activities reviewed included:

| | |
|---|---|
| MO 0199600291 | Run-in OC DG, Perform Inspections, Change Out Engine |
| MO 0199600129 | Inspect & Replace Cylinder Liners & Rings, OC Diesel |
| MO 2199600133 | #21 Service Water Heat Exchanger - Remove Epoxy on Tubes ID |
| MO 2199600591 | Repair End Bells on 21 Letdown Heat Exchanger |

#### M1.2 Maintenance Problems Cause Loss of MCC 205R and a Change in Pressurizer Pressure Indication

On March 18, BGE mobile maintenance electricians caused the loss of 480V Motor Control Center (MCC) 205R while installing a power supply connection into a spare breaker cubicle on the MCC. As the electricians were pulling the cable leads through the cubicle panel, one of the leads shorted to the energized MCC bus bars causing smoke and damage to the MCC. The MCC feeder breaker opened on the fault. Power was lost to several radiation monitor pumps, the 21 reactor coolant makeup (RCMU) pump, and the refueling water tank (RWT) recirculation pump. The RCMU and RWT recirculation pumps were not in use at the time. Control room operators immediately entered the appropriate abnormal operating procedure for loss of the MCC, and established compensatory measures for the lost equipment. There were no personnel injuries, and following inspection and evaluation, the MCC was returned to service the next day. BGE characterized the incident as a potential fatal "near miss" and began an independent safety evaluation group (ISEG) investigation.

On March 18, instrument technicians installing a test lead from a recorder inadvertently grounded the lead and introduced a step change decrease in pressurizer pressure indication 2-PIC-100X, causing all pressurizer backup heaters to energize. The recorder was part of a temporary alteration being installed to monitor performance of a deficient Unit 2 reactor regulating system channel. The pressurizer pressure channel alarmed, and control room operators noted the backup heaters energize. All other pressurizer pressure indications were normal. Operators de-energized three banks of heaters and the technicians immediately stopped their work. There was approximately a five pound rise in actual pressure during the transient. When the ground was removed, the pressure indication returned to normal. Installation of the temporary alteration was stopped by BGE pending review of the event and engineering evaluation of the temporary alteration.

As corrective actions, BGE supervisors discussed the events with maintenance and engineering personnel. Also, BGE management informed the inspectors that additional corrective actions may result from investigation of the events. The inspectors considered the safety consequences of the events to be minor. However, when considered in the aggregate with other maintenance problems that occurred during the inspection period, the inspectors were concerned that BGE procedures and programs in this area may not be fully effective in ensuring that maintenance activities were being accomplished in a fully effective manner.

M1.3 <u>Outage Preparations</u>

In preparation for the Unit 1 refueling outage that began on March 29, BGE personnel associated with the steam generator (S/G) eddy current testing briefed the inspectors on their activities, including test predictions and contingency plans. The planned inspections included:

- 100% full length with bobbin coil
- 100% hot leg side in the tube sheet area with plus point probe
- 20% dented tube support intersections
- 20% of Rows 1 and 2 tight radius U-bend regions
- 20% steam blanket region

Additionally, selected tubes were to undergo in-situ pressure testing, three tubes would be pulled for metallurgical analysis, and the tube sheet sludge pile would be sampled for chemical analysis.

Based, in part, on the results of the inspections performed on the Unit 2 steam generators in 1995, as well as engineering predictive analysis, BGE expected to plug about 200 tubes in 11 S/G and 175 tubes in 12 S/G. BGE had established contingency plans to be used if substantially more than the expected number of tubes had crack indications.

On the secondary side of the S/Gs, BGE intended to inspect and clean the steam dryer components, inspect the secondary side feedwater internals, and test-fit a device to perform sludge lancing.

BGE also indicated that a temporary cover would be staged to provide closure to the equipment hatch for additional containment integrity if needed, during the eddy current inspections. The power and signal cables were passed into the containment through sealed penetrations in the equipment hatch and the cables were terminated to facilitate removal if it became necessary to close the hatch. Additionally, plans specified that an individual would be assigned to assist in the process of closing the equipment hatch should containment integrity be required.

The inspectors noted that the BGE personnel demonstrated an appropriate regard for nuclear safety, as indicated by controls instituted to ensure containment integrity during fuel moves and periods of reduced reactor water inventories.

M1.4 Routine Surveillance Observations

The inspectors witnessed/reviewed selected surveillance tests to determine whether 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. The inspectors noted that an appropriate level of supervisory attention was given to the testing depending on its sensitivity and difficulty. Surveillance testing activities that were reviewed are listed below:

| | |
|---|---|
| SAT-1A024F-04 | 1A Diesel Generator Endurance Run |
| ETP 95-029 | 1A DG Slow Start and Emergency Start From 1C18A |
| STP-M-672-B2 | Pressurizer Relief Valve MPT Channel Functional Test |
| STP-M-672-B1 | Pressurizer Relief Valve MPT Channel Functional Test |

M1.5 Relief Valve Opens During Surveillance Testing

On February 28, 1996, during the performance of STP-M-672-B-2, "Pressurizer Relief Valve MPT Channel Functional Test," pressurizer relief valve 2-ERV-404, was inadvertently opened. Although Unit 2 was at normal pressure and temperature, plant conditions were not affected because the associated pressurizer relief block valve was shut. The inadvertent opening occurred when instrument and control technicians connected a multimeter to leads in the minimum pressure and temperature (MPT) control circuit for the relief valve, while testing the MPT function for both relief valves 2-ERV-402 and 404. The test was done following the trip of Unit 2 on February 27, in preparation for entry into Mode 5. The MPT circuits were tested to verify the capability of the pressurizer relief valves for over-pressure protection during cold shutdown conditions.

The cause of the inadvertent opening of the ERV was a weak procedure. During testing of the MPT control circuits, conditions were established to simulate MPT conditions and verify that appropriate valve control circuit contacts shut when required. Because the surveillance procedure being used by the technicians was not detailed, drawings were required to determine the exact physical location to attach the multimeter during various steps in the test sequence. Testing was done on 2-ERV-402 first and using the drawings the test was completed satisfactorily. When ERV-404 was tested, immediately after ERV-402, the drawings were not appropriately interpreted, and the multimeter was connected to the wrong contacts. The logic for MPT protection was established and the relief valve opened. Because the block valve had been shut as specified in the procedure, plant conditions were not affected.

The inadvertent opening of the ERV was identified by the technicians and the testing was halted. An issue report was generated and a supervisory review of the event was done before the testing was resumed and completed satisfactorily. BGE later revised the procedure to include a detailed description of where the multimeter should be connected during the test sequence. Additionally, a caution was added to the procedure stating that connecting to the wrong contacts could result in opening of the relief valve. The inspectors considered the corrective actions taken by BGE to be appropriate. The issue was considered a Non-Cited Violation, consistent with Section VII of the NRC Enforcement Policy.

## M7 Quality Assurance in Maintenance

### M7.1 Use of Probabilistic Risk Assessment in Maintenance Activities

Following the February 27, 1996 loss of offsite power event, the inspectors questioned BGE as to the acceptability of planned activities that included conduct of switchyard troubleshooting coincident with maintenance that included on-line repair of a Unit 1 turbine driven auxiliary feedwater pump and service water header work on shutdown Unit 2 that would have disabled 21 Emergency Diesel Generator. The inspectors considered the risk of a loss of offsite power to be increased during switchyard troubleshooting, especially in light of the February 27 reactor trip. The Calvert Cliffs daily risk evaluation for the period following the trip included the scheduled auxiliary feedwater and service water header maintenance, as well as a slight increased probability of loss of offsite power due to the 5052 transmission line being out-of-service, but no added risk due to troubleshooting. Troubleshooting activities were risk assessed in the troubleshooting documentation based on the nature of the individual tasks and were not used in determining overall increased risk of the activity on the plant.

BGE, in response to inspector concerns, determined that the risk model used in determining the acceptability of on-line maintenance sequencing in general, accounted for equipment being out-of-service, but not for the increased risk of technician error during the work. The PRA model used in maintenance scheduling did not include an assessment of human factors that could result in an increased probability of a transient caused by the maintenance being conducted. A BGE PRA analyst stated that the added risk of human error during troubleshooting was not easily quantified.

In an immediate response to the inspector concerns, BGE halted switchyard troubleshooting on February 28, until both the auxiliary feedwater pump on Unit 1 and the Unit 2 service water header and diesel were restored to service. The troubleshooting was then accomplished with all plant accident mitigation equipment in full readiness. Additionally, a review of maintenance sequencing was conducted and the effects of troubleshooting on overall transient prevention and accident mitigation were evaluated. Interim actions identified by BGE included;

- The separate risk evaluation methods for maintenance and troubleshooting were to be evaluated to include troubleshooting risk in overall risk of maintenance activities.

- Troubleshooting and maintenance scheduling was to be screened for the added risk associated with human error. Emergent higher risk activities such as troubleshooting, were to be assessed for impact on scheduled work and when practical, equipment would be returned to service before troubleshooting to minimize overall plant risk.

- Plant operators were informed that BGE probabilistic risk assessments do not necessarily include the increased risk due to technician or operator error during maintenance. Operators, having received PRA training, were requested to independently assess the risk level of maintenance or troubleshooting activities as a check that adequate controls were in place for emergent work.

The inspectors observed that risk assessment was used to minimize the safety impact of scheduled maintenance and troubleshooting. On March 6, maintenance on 13 HPSI pump was delayed to allow completion of maintenance on 12 salt water header. The inspector considered the BGE actions to include human factors and troubleshooting in maintenance risk evaluation to be an appropriate upgrade to the Calvert Cliffs risk assessment program.

## III. Engineering

### E1 Conduct of Engineering

New Emergency Diesel Generators (EDG) (37700)

This portion of the inspection was to review BGE's corrective actions in response to the EDG cylinder liner scuffing problem identified in December 1995. The inspection covered the root cause analyses, selection of new lubrication oil, post-modification testing, long-term monitoring program of diesel engine cylinder conditions, and management oversight in handling the scuffing problem.

E1.1 <u>EDG Cylinder Scuffing Problem</u>

During preoperational testing of the new safety-related EDG 1A in November 1995, diesel engine 1A2 (EDG 1A has two diesel engines) experienced high and erratic crankcase pressure (up to 1.8" water). Boroscopic inspection of 1A2 cylinders revealed that cylinder 1A2-B7 had a symptom of a stuck upper compression ring (the ring became non-movable). Subsequent removal of this cylinder confirmed the stuck ring problem. This cylinder was replaced and the damaged parts were shipped to SACM, the diesel engine manufacturer, for evaluation. Additional tests followed.

A full boroscopic inspection (required by test procedure) of both engines 1A1 and 1A2 was conducted in January 1996. This inspection revealed four cylinders (1A1-A3, 1A1-A5, 1A2-B1 and 1A2-B8) with scuffing, all at the master rod side of the engine. Close examination of the removed cylinder heads revealed excessive carbon buildup behind the piston rings. BGE immediately conducted an inspection of all cylinder liners and piston rings of EDG 1A. The inspection results prompted BGE to replace all cylinder liners and piston rings of EDG 1A. Boroscopic inspection of the station blackout (SBO) diesel cylinders indicated that scuffing problem also affected the SBO diesel. BGE also replaced the SBO diesel cylinder liners and piston rings.

E1.2 <u>Problem Analyses and Root Cause Evaluations</u>

BGE initiated multiple problem analyses and root cause evaluations to meet the tight operational schedule. These included analyses from BGE material and chemistry department, Mobil Oil (previous lube oil supplier), SACM (diesel generator unit supplier), Ricardo Engineering (diesel generator expert), and Failure Prevention Incorporated (root cause analyses expert). In addition, BGE formed a root cause evaluation team, consisting of five team members, to integrate all the analysis findings. The results of the integrated root cause evaluation were documented in BGE Root Cause Analysis Report 96-01, "1A Diesel Generator Problem," dated March 29, 1996.

The inspector's review of BGE's failure analyses indicated these analyses to be thorough and logical. A structured decision analysis methodology was frequently used. All possible causes were identified and analyzed. Logical bases were used to eliminate those causes that were determined to be invalid. The invalid causes included: incorrect piston rings, piston rings improperly installed, incorrect powerpack dimensions, improper operation of the EDG, etc. The final conclusion reached by BGE for the cause of the failure was incompatibility between the Mobilgard SHC-120 lube oil and diesel fuel. This incompatibility caused excessive combustion product deposit at the piston ring grooves, expanding the piston rings, resulting in cylinder liner scuffing. The major cause of the incompatibility was the extra-low sulfur content of the diesel fuel used in EDG 1A.

Although ASTM Standard D-975 for the diesel fuel specified a maximum sulfur content of 0.5% (State of Maryland environmental regulations specified a maximum sulfur content of 0.3%), the diesel fuel used in EDG 1A had a sulfur content of 0.04%, much lower than that expected by the diesel engine manufacturer.

Normal lube oil contains additives to neutralize combustion products. One of the additives was sulfated ash which was used to neutralize sulfuric acid to prevent engine part corrosion. Appropriate amount of additive was specified for a specific lube oil to be used for an engine burning diesel fuel of specific sulfur content. Too low a sulfur content of a diesel fuel could cause insufficient sulfur to react with the lube oil additive, which could form undesired deposits when the lube oil was burned. The SACM-built engine was designed for relatively high lube oil consumption rate, resulting in more combustion product deposit.

The inspector's review of the SACM technical manual revealed that Mobilgard SHC-120 CE rated lube oil was specified. This lube oil was selected by SACM because of the successful operation in many EDGs in the French nuclear industries. BGE later found out that Mobilgard SHC-120 used at Calvert Cliffs and the Mobilgard SHC-120 used by the French nuclear industries were of different formulation. The French one was of older type, petroleum-based (actually designated as Mobilgard SHC-120F), and was not available in the United States, while the one used at Calvert Cliffs was of more recent type, synthetic-based, and only qualified as CD rated [American Petroleum Institute (API) rating].

The inspector's review of the two formulations (presented by Mobil) indicated that the additive chemicals differed significantly, and the lube oil total base numbers (TBNs) were also different. The other contributing factor was that the sulfur content in the French diesel fuel was 0.25%, much higher than the diesel fuel used at Calvert Cliffs. BGE material and chemistry department was responsible for diesel fuel and lube oil analyses. The inspector's review of the diesel fuel analysis indicated that BGE knew about the extra-low sulfur content of the diesel fuel as early as April 1995. However, BGE did not recognize the potential problem that could be caused by diesel fuel and lube oil incompatibility. Therefore, BGE did not communicate this (extra-low sulfur content) to the diesel manufacturer. This lack of communication was considered by the integrated root cause evaluation team to be an underlying root cause for the lube oil and diesel fuel incompatibility. The other contributing factor was that both ASTM Standard D-975 and BGE's procurement specification did not specify the lower limit of the sulfur content in the diesel fuel. The root cause evaluation team made five recommendations to BGE management as a long-range resolution of the diesel cylinder liner scuffing problem:

1) Request the diesel manufacturer to revise their technical manual to accept the use of the new lube oil (Shell Rotella-T, a CG-4 rated oil);

2) Develop a long-range monitoring plan which would provide a means to validate the successful performance of the new lube oil;

3) Determine if it would be necessary to revise the engineering parameter that was specified with a maximum or a minimum value (such as the sulfur content in the diesel fuel) to one with a specific range;

4) Verify the API rating on the lube oil drum during receipt inspection;

5) Determine if there were any key parameters for CG-4 lube oil, that could be easily measured during receipt inspection and could demonstrate that the accepted formulation limits were not exceeded.

The inspector concluded that BGE, in response to the diesel cylinder liner scuffing problem, had completed extensive and thorough problem analyses and root cause evaluations. A structured decision methodology was frequently used in those analyses. As a result of these analyses, failure root causes and required corrective actions were promptly identified.

E1.3 New Lube Oil Selection

The inspector reviewed BGE's methodology and rationale for selecting a new lube oil to replace the old lube oil to determine whether the selection was based on sound engineering evaluation.

BGE hired Ricardo Engineering of Burr Ridge, Illinois, to perform failure analysis and new lube oil selection. The inspector interviewed the two consultants from Ricardo Engineering and found them very knowledgeable in diesel engines and lube oil.

The failure analysis identified that the cylinder liner scuffing was due to incompatibility of diesel fuel and lube oil, causing excessive deposit of combustion products in the piston ring grooves. To select a suitable new lube oil for the low sulfur fuel, BGE compared various lube oils including: Mobilgard SHC-120, Mobilgard SHC-120F, Mobilgard 412 (used at Prairie Island), and Shell Rotella-T (a CG-4 rated oil). This comparison was based on the specific operating conditions at Calvert

Cliffs, including low sulfur content diesel fuel, low oil sump temperature, engine designed for high oil consumption, engine required for fast starts, preheated and prelubed condition, recommended two year lube oil change interval, and cost. Result of this comparison indicated that Shell Rotella-T was the most suitable lube oil for Calvert Cliffs' application. The main factors for consideration were that CG-4 lube oil contained low sulfated ash and was formulated for low sulfur content diesel fuel (less than 0.2%).

The rationale for lube oil selection was documented in a Ricardo report (RNA96/043) dated February 19, 1996. This report also covered a test plan to validate CG-4 lube oil in Calvert Cliffs' SACM engines, including acceptance criteria for the post-test inspections. The inspector's review of this report indicated that the analysis was thorough, the test plan contained logical steps, and the acceptance criteria was based on sound engineering judgement.

The inspector concluded that BGE used a logical methodology for new lube oil selection which was based on thorough engineering evaluations.

E1.4 Emergency Diesel Generator Testing

The inspector reviewed BGE's post-modification testing to determine if adequate tests were performed and that the tests were conducted in accordance with established test procedures.

BGE generated test procedure SAT-1A024F-04, "1A Diesel Genset Endurance Run," for the post-modification testing. The test procedure covered the following purposes:

1) Qualify and validate the new lube oil (Shell Rotella-T, CG-4 rated) for use in the SACM engines;

2) Run-in new piston rings and cylinder liners per diesel vendor manual;

3) Verify proper engine operating parameters and conditions following the two year maintenance;

4) Perform lube oil consumption test to establish baseline;

5) Verify that the engine cylinder liner scuffing problem was corrected.

The inspector's review of the test procedure indicated the procedure was well written, and contained appropriate acceptance criteria. It also included the test plan recommended by Ricardo Engineering to validate the new lube oil.

The tests were conducted from February 26 to March 11, 1996. The tests consisted of various discrete steps. Engine 1A1 was tested first, then engine 1A2, followed by running both engines together. The inspector's review of the test records of 1A1 engine indicated that the tests included the following sequence: 1) slow start and loaded engine gradually to full load for 11 hours, checked oil consumption, full boroscopic inspection of all 1A1 cylinders, run engine again at full load followed by another full boroscopic inspection, then removed four cylinder liners and pistons for close examination.

The post-modification tests were completed March 11, 1996. The results of the boroscopic inspections and the disassembled engine liner and piston ring inspections indicated all conditions were normal. The lube oil consumption rate was reduced by two-thirds and the oil sample analysis indicated normal lube oil condition. BGE, therefore, determined that the new lube oil was qualified and compatible with the low sulfur diesel fuel, and that the engine cylinder liner scuffing problem was corrected.

During the week of March 18, 1996, BGE conducted a preoperation test of EDG 1A, using control from the main control room. Test Procedure ETP 95-029, "1A DG slow start and emergency start from 1C184," Revision 0, dated November 10, 1995 was used for the test. The inspector reviewed procedure ETP 95-029, and witnessed a portion of the test, which consisted of two parts; a four-hour slow start test and a one-hour emergency start test. EDG 1A functioned properly during these tests. The test procedure contained adequate detail and acceptance criteria.

During all the above tests, all EDG loads were connected to a temporary load bank located next to the new EDG building. The inspector's review of BGE's schedule indicated that EDG 1A would be connected to the safety related bus during the next refueling outage, starting on March 29, 1996. All future tests would be conducted by plant operations, using plant engineering and surveillance procedures, and the EDG load would be connected to the grid.

Because diesel cylinder liner scuffing also affected the SBO diesel, the SBO diesel generator also received post-modification testing on March 20, 1996. Following successful testing of EDG 1A, BGE replaced the SBO diesel lube oil with Shell Rotella-T lube oil. Since the new lube oil had already been demonstrated to be qualified, the SBO diesel testing was only to demonstrate that the replaced cylinder liners and piston rings functioned satisfactorily. The test for the SBO diesel was completed successfully on March 28, 1996.

The inspector concluded that BGE had conducted sufficient tests to demonstrate that: 1) the newly selected lube oil (Shell Rotella-T CG-4 oil) was qualified for the SACM diesel engine and low sulfur diesel fuel; and 2) the replaced cylinder liners and piston rings functioned properly for EDG 1A and the SBO diesel. The test procedures were well written and contained appropriate acceptance criteria.

E1.5 Long Range Monitoring Program for Diesel Engine Cylinder Conditions

The inspector discussed with BGE system engineering the long range monitoring program for the diesel engines to ensure continued operational success of the newly replaced cylinder liners and piston rings. BGE stated that the program had not yet been finalized. However, during the last week of the inspection, BGE presented to the inspector the proposed maintenance plan for the next two years as follows:

1) Trending Program for both EDG 1A and SBO diesel: Trend engine operating data, particularly crankcase pressure and lube oil filter fouling rate, for each engine run.

2) Monthly: Oil analysis to be reviewed by SACM as available, oil running hours and amount of oil added would also be reviewed.

3) Annually: Boroscopic inspection of four cylinders per engine for EDG 1A (because 1A diesel accumulated most hours since oil change), lube oil filter analysis, centrifugal oil filter inspection, and lube oil consumption test.

4) Every Two Years: Boroscopic inspection for all cylinders, check valve lash, check fuel injector calibration, replace lube oil and fuel [illegible] filters, check diesel generator alignment, check crankshaft thrust, check injection timing, clean centrifugal oil filter, inspect air intake manifold, clean crankcase breather filters, clean intake air filters, replace starting air filters, inspect generator coupling, and check overspeed detectors.

BGE stated that the maintenance program would be finalized and implemented once approved by the management. The inspector agreed that this was an acceptable maintenance plan for the new diesel generators. The inspector's review of BGE's integrated root cause analysis report indicated that this long range monitoring program was also recommended by the root cause team, and accepted by System Engineering. Since BGE already had a tracking mechanism for the implementation of this program, the inspector determined that NRC's tracking of this program was not necessary.

E1.6 Management Oversight of the Diesel Engine Cylinder Liner Scuffing Problem

The inspector reviewed management oversight of the diesel generator project to determine if management was involved in providing management directions to resolve the diesel engine cylinder liner scuffing problem.

When the cylinder liner scuffing problem was identified in January 1996, the management made a prompt decision to replace all cylinder liners and hired very knowledgeable consultants (Ricardo Engineering and Failure Prevention Inc.) to conduct failure analysis and root cause evaluations. BGE management also mobilized substantial manpower within BGE to assist the consultants to quickly identify the root causes and the required corrective actions. This prompt decision enabled the cylinder liner scuffing problem be resolved on time, and minimized the effect on delaying Calvert Cliffs' refueling outage.

In addition, the management also formed an integrated root cause analysis team to: 1) validate the root causes that were identified by the consultants; and 2) identify long range corrective actions (recommendations to management) to enhance successful future operation of the new EDG, and to prevent recurrence of cylinder liner scuffing problems.

The inspector concluded BGE had good management oversight in providing directions to promptly resolve the diesel engine cylinder liner scuffing problem. This prompt action minimized the impact on delaying Calvert Cliffs' operation schedules. In addition, long range corrective actions were identified to enhance successful future operation of the new EDGs.

E1.7 General Conclusion

BGE responded appropriately following the identification of the cylinder liner scuffing problem (for the new diesel generators) in January, 1996. Extensive effort was provided by BGE management to promptly identify the failure root causes and implement appropriate corrective actions. The problem was resolved within the tight operational schedule. The impact of this problem on delaying the refueling outage was minimized. The integrated root cause analysis team properly integrated and validated the root cause findings from various consultants and vendors. The root cause analysis reports were of good quality. A structured decision methodology was frequently applied during the analysis process. The methodology used by BGE to select a new lube oil for the low sulfur diesel fuel was logical. Management oversight for resolving the cylinder liner scuffing problem was very good.

## E8 Miscellaneous Engineering Issues

Status of Previously Identified Electrical Distribution System Functional Inspection (EDSFI) Item (2515/111)

(Closed) Unresolved Item (50-317/318/92-80-09): Emergency Switchgear Room HVAC

During the 1992 EDSFI, the team identified that BGE did not adequately evaluate the adverse affect for a total loss of HVAC to the emergency switchgear rooms (ESR). The team determined that the following issues need to be addressed by BGE:

1. Completing analysis that addresses all the accident scenarios including total loss of ventilation air flow.

2. Modifying the operating procedures to ensure the assumed initial conditions required to support the calculated thermal transients.

3. Amending the operating procedures to ensure that adequate equipment and instructions are provided to reliably establish long-term cooling.

4. Resolving the Appendix R issues related to the HVAC system.

In a response letter dated July 8, 1992, BGE identified all corrective actions to be taken to resolve the above issues.

This item had been updated during the June 1993 (Inspection No. 93-21) and the August 1995 (Inspection No. 95-08) EDSFI followup inspections.

There were two redundant ESRs in each unit, one located at 27' elevation; the other was directly above at 45' elevation. Directly above the 45' ESR was a mechanical equipment room which housed redundant HVAC units. One HVAC unit was required to operate continuously to cool both ESRs and other areas, both during plant operation and plant shutdown. Each unit consisted of a supply fan, a cooling coil and a filter. These redundant HVAC units shared a common outside air duct and a common discharge duct, which were susceptible to a common mode failure.

The inspector's review of Calvert Cliffs Updated Final Safety Analysis Report (UFSAR) Section 9.8.2.3, "Auxiliary Building Ventilation Systems," Revision 15, indicated that the system design for the switchgear room HVAC was consistent with the current configuration. The inspector also reviewed the July 16, 1971, version of Calvert Cliffs Final Safety Analysis Report (FSAR). In that version, the description of the ESR HVAC system did not contain redundant HVAC units. However, in the August 15, 1972, version FSAR, the system description was revised, stating that redundant fans and refrigeration equipment were provided. This indicated that the design of the ESR HVAC system had been revised at that time, possibly in response to the NRC's questions.

BGE stated that the licensing basis for Calvert Cliffs, at that time, was not to postulate a single passive failure during an accident. Only single active failure, such as fans and refrigeration equipment failure, could be postulated. Therefore, the only concern involving common mode failure was those conditions due to a 10 CFR 50 Appendix R fire.

According to BGE, one ESR must be unaffected for each unit to provide safe shutdown of the plant. Based on BGE's analyses, the worst condition would be one caused by a fire in the 45' ESR. A fire in the 45' ESR could damage the 45' ESR and cause the fire dampers to close, cutting off ventilation to the 27' ESR. BGE's calculations indicated that, with a total loss of ventilation, the 27' ESR temperature would increase from 104°F to 150.4°F within 30 minutes. BGE's compensatory measure for this condition was to provide manual cooling to the 27' ESR, using a portable fan and a portable standby generator. BGE also wrote Procedure OI-22H, Section 6.7, "Operation of Emergency Portable Switchgear Room Ventilation," to stage the manual cooling equipment.

During this inspection, BGE walked through this procedure and demonstrated that, under no-fire conditions, the staging was completed within 10 minutes. The inspector reviewed this procedure and found it acceptable. The inspector also determined that operation personnel were available to stage manual cooling during a fire. The inspector walked down the manual cooling equipment, and found the equipment was in a ready-for-use condition.

BGE had also completed two additional calculations; one calculation, E-91-02, performed by Mainline Engineering, was to demonstrate that the electrical equipment was operable at 150°F for short duration. The inspector's review of this calculation indicated the calculation to be acceptable. The other calculation, No. MLEA-90-03, Revision 2, was to demonstrate that, with the initial temperature of 150°F and the portable fan operating, the 27' ESR temperature would cool down to a final equilibrium temperature of 135°F. This calculation was based on a cooling air temperature of 123°F from the turbine building, and an air-flow of 10,000 cfm. The portable fan used for the cooling was a two speed Dayton Model 3C187, 36-inch fan, rated at 10,300 cfm at high speed.

The 27' ESR is a room approximately 30 ft x 50 ft, containing electrical equipment; some of which is safety-related. One 50 ft. wall is adjacent to the turbine building and had two doors, an equipment rollup door (about 10 ft x 10 ft) near one end and an access door (about 3 ft x 7 ft) near the other. During the manual cooling mode, the portable fan was to be placed at the equipment door with the rollup door pulldown to the top of the fan. When the portable fan was in operation, there was an opening twice the size of the fan that permitted the air to recirculate, and to short-circuit the cooling function. The inspector asked BGE engineers how could they demonstrate that sufficient air (10,000 cfm) would pass through the ESR, cool the electrical equipment, and exit the access door at the other end of the room. Insufficient cooling air flow would cause the temperature calculation to be invalid, the safety-related electrical equipment in the 27' ESR to be inoperable, and jeopardize the safe shutdown capability. This condition could be in contrary to Calvert Cliffs' fire protection program, Section D.1, Part (b), which states, in part, that, "...a postulated single fire cannot disable both redundant safe shutdown equipment and components." At the time of the inspection, BGE could not provide any valid answer to the above question.

In response to the inspector's concern as described above, BGE promptly revised Procedure OI-22H, Section 6.7 to use two portable fans instead of one fan. Using two fans would double the flow capacity and reduce the recirculating opening by one half. BGE estimated that using two fans would increase the staging time by about 5 minutes, still within the allowed 30 minutes total staging time. BGE also told the inspector that a test plan would be developed to test the air flow in 27' ESR for both cases: 1) when one portable fan was used; and 2) when two portable fans were used. This test was scheduled for May 2, and was to determine whether sufficient air flow (10,000 cfm) was ever available to cool the

27' ESR during the emergency condition. This item is unresolved pending BGE's test result to demonstrate compliance with Calvert Cliffs' fire protection program (50-317/318/96-02-01).

The original unresolved item (50-317/318/92-80-09) is closed.

## IV. Plant Support

### R1 Radiological Protection and Chemistry (RP&C) Controls

R1.1 Radioactive Liquid and Gaseous Effluent Control Programs

To verify the implementation of the technical specification (TS) and the Offsite Dose Calcuiation Manual (ODCM) requirements, the inspector toured the plant, reviewed the following selected BGE procedures, and reviewed selected radioactive liquid and gaseous discharge permits:

- CP-212, Specifications and Surveillance Radioactive Liquid Waste Releases
- CP-601, Liquid Radioactive Waste Release Permit
- CP-614, Unmonitored Liquid Radioactive Waste Release Permit
- CP-213, Specifications and Surveillance Radioactive Gaseous Waste Release
- CP-604, Radioactive Gaseous Waste Permits
- CP-612, Plant Main Vent Releases

During the tour, the inspector noted that all effluent radiation monitoring systems (RMS) were operable. During the review of the above radioactive liquid and gaseous effluent procedures, the inspector noted that the procedures were easy to follow, and contained sufficient level of detail.

The inspector also determined that the reviewed discharge permits were complete and met the TS/ODCM requirements for sampling and analyses at the required frequencies, and met the lower limits of detection established in the TS.

The inspector also observed the liquid radwaste effluent radiation monitor readings during a discharge. The RMS response was calculated using the conversion factor established by the Chemistry staff and was recorded in the permits. The monitor responded as predicted by the Chemistry staff.

During the discussion with the Chemistry Department staff, the inspector noted that the responsible individuals had maintained, and continually enhanced, their excellent knowledge in the areas of: (1) radioactive liquid and gaseous effluent controls, (2) effluent/process RMS, (3) protection of the public health and safety and the environment, and (4) effluent ALARA concepts and practices.

R1.2 Implementation of Effluent ALARA (As Low As Reasonably Achievable)

In 1995, the Chemistry staff launched the implementation of Effluent ALARA through several projects, including the use of improved resins for the reactor coolant waste system, to minimize radioactivity releases tothe environment. During 1995, BGE released 245 millicuries through liquid releases compared to 795 millicuries in 1994, and 83.7 curies through gaseous releases compared to 147.9 curies in 1994. These releases were below 1995 goals.

The Chemistry Department staff published the "1996 Chemistry Business Plan," which outlined strategies (interdepartmental and systems performance) to achieve the Effluent ALARA, as well as the in-plant ALARA. Due to the apparent success in reducing effluent radioactivity, BGE established even lower goals for 1996.

Based on the reviews and discussions with the Chemistry staff, the inspector determined that BGE had excellent radioactive liquid and gaseous effluent control programs and was successfully achieving effluent ALARA results. The inspector also noted that BGE management supported the effluent control programs, and the Chemistry staff continued to critically review the effluent control programs vigorously with a view toward further improvement.

R1.3 Refueling Outage Preparations

Prior to the start of the Unit 1 refueling outage, the Radiation Safety Section established a preventive process to verify that individuals entering the auxiliary building were wearing proper dosimetry and were logged onto the correct special work permit (SWP). After the normal log-in process, a radiation safety technician at the entrance to the auxiliary building questioned workers before entry as to the nature of their work, verified proper dosimetry, and reviewed the SWP with the worker. The verification process was considered by the inspectors to be a very good initiative in the BGE radiation control program.

**R2 Status of RP&C Facilities and Equipment**

R2.1 Calibration of Effluent and Process RMS

The inspector reviewed the most recent calibration results for the following effluent/process RMS to verify the implementation of the TS requirements and FSAR commitments for both units:

- Steam Generator Blowdown Radiation Monitors (Units 1&2),
- Liquid Radwaste Effluent Radiation Monitor (Common),
- Containment Atmosphere Radiation Monitors (Units 1&2),
- Wide Range Noble Gas Monitors (Units 1&2),
- Main Plant Vent Noble Gas Monitors (Units 1&2),
- Waste Gas Discharge Noble Gas Monitor (Common),
- Condenser Vacuum Pump Discharge Radiation Monitors (Units 1&2), and
- Spent Fuel Pool Vent Gaseous Radiation Monitor (Common).

The Instrument and Controls Department had the responsibility to perform electronic and radiological calibrations for the above radiation monitors. All reviewed calibration results were within BGE's acceptance criteria. The calibration efforts were well done and exceeded the quality specifications detailed by the applicable regulatory requirements.

The inspector discussed the maintenance of operability with the RMS System Engineer and members of the Chemistry staff. From these interviews, the inspector determined that these individuals had excellent knowledge of the RMS relative to operability requirements and performance history. The inspector noted that BGE was in the process of upgrading the condenser offgas monitors for both units. These monitors were located in a harsh power plant environment (high humidity and temperature), therefore, BGE had difficulties maintaining good operability. The upgrading project will be completed by the end of 1996 for Unit 1 and the end of 1997 for Unit 2. BGE is also planning to upgrade the main vent effluent sampling skid (sampling for particulates, iodine, and tritium) for both units.

Based on the above reviews, the inspector determined that BGE's performance and achievements, relative to calibration of the RMS and the upgrading projects, were excellent for maintaining good operability and reliability of the system.

R2.2 Air Cleaning Systems

The inspector reviewed BGE's most recent surveillance test results to verify the implementation of TS requirements for the following air cleaning systems:

- Control Room Emergency Air Supply Systems,
- Spent Fuel Handling Building Exhaust System,
- Penetration Room Exhaust System, and
- ECCS Pump Room Exhaust System.

The inspector reviewed the following surveillance test results:

- Visual Inspection,
- In-Place HEPA Leak Tests,
- In-Place Charcoal Leak Tests,
- Air Capacity Tests,
- Pressure Drop Tests, and
- Laboratory Tests for the Iodine Collection Efficiencies.

All test results were within BGE's TS acceptance criteria, with the exception of the in-place charcoal leak test for ECCS Pump Room Exhaust Systems for both units, and the laboratory test for the iodine collection efficiency for Unit 2. Corrective actions required by the TS, including retest and charcoal replacement, were taken immediately and retest results were within the TS acceptance criteria.

The inspector noted that the visual inspection items in the surveillance procedure were not detailed, but that the procedure was in the process of revision. The inspector reviewed the draft procedure and no deficiencies were observed.

During an inspection conducted in January 1995, the inspector previously noted that BGE identified a weakness in the testing criteria for laboratory tests for the iodine collection efficiency as specified by Technical Specification Section 3/4.6.3, "Iodine Removal System of the Containment Systems." Testing conditions of the system required by the TS for the iodine collection efficiency are at 130°C and 95% relative humidity. BGE determined that the test temperature (130°C) was too high since testing at that temperature could recondition the charcoal and greatly increase its apparent collection efficiency above the actual efficiency during normal use. While BGE conformed to the 130°C test specification, the charcoal filter system was also tested at 30°C. As a result of the low temperature test, BGE replaced charcoal banks from the iodine removal system during outages.

Testing temperature required by the technical specifications for other air cleaning systems, such as the control room emergency air supply systems, is 30°C. BGE will use the same testing criteria during the Unit 1 outage scheduled in March 1996. Accordingly, BGE stated that a TS amendment may be submitted to the NRC upon the completion of the test.

Based on the above reviews, the inspector determined that BGE's performance and achievements, relative to the pursuit of better charcoal testing practices and criteria, were excellent.

**R3 RP&C Procedures and Documentation**

R3.1 Review of Semiannual Radioactive Effluent Reports

The inspector reviewed the 1994 and the first half of 1995 semiannual radioactive effluent release reports. These reports provided data indicating total released radioactivity for liquid and gaseous effluents. These reports also summarized the assessment of the projected maximum individual and population doses, resulting from routine radioactive airborne and liquid effluents. Projected doses were well below the technical specification limits. The inspector determined that there were no obvious anomalous measurements or omissions in the reports.

BGE implemented the Effluent ALARA program rigorously during 1995, and the total amount of radioactive liquid and gaseous releases from the plant were reduced significantly (see Section R1.2 of this inspection report for details).

R3.2 <u>Review of Offsite Dose Calculation Manual (ODCM)</u>

The inspector reviewed BGE's current ODCM. The ODCM provided descriptions of the sampling and analysis programs, which are established for quantifying radioactive liquid and gaseous effluent concentrations, and for calculating projected doses to the public. All necessary parameters, such as effluent radiation monitor setpoint calculation methodologies, site-specific dilution factors, and dose factors, were listed in the ODCM. BGE adopted other necessary parameters from Regulatory Guide 1.109.

Based on the above review, the inspector determined that BGE's ODCM contained all necessary information and instruction to establish and implement the radioactive liquid and gaseous effluent control programs, and the Radiological Environmental Monitoring Program.

## R6 RP&C Organization and Administration

The inspector reviewed the organization and administration of the radioactive liquid and gaseous effluent control programs. The inspector determined that there were no changes to the radioactive effluent control programs since the last inspection conducted in January 1995. The Chemistry Department has primary responsibility for conducting the radioactive liquid and gaseous effluent control programs. Other responsible groups for the programs are: (1) Operations, (2) Electrical and Controls (E&C), (3) System Engineers, and (4) Radwaste Operations.

## R7 Quality Assurance (QA) Audits in RP&C

The inspector reviewed the 1995 QA Audit Report (Report No. 95-3). The audit was conducted by the Nuclear Quality Assurance Department (NQAD) staff and covered the radioactive liquid and gaseous effluent control programs. The inspector also noted that BGE conducted the Surveillance Audit (Audit No. S-95-3-2) and the Quality Verification Surveillance Audit (Audit No. QVOS95025) for the effluent control programs during 1995. These audits were conducted by the NQAD staff with assistance from other technical specialists, including a specialist from another utility. The 1995 audit team concluded that the Chemistry Department implemented excellent effluent control programs. The team made one observation regarding the use of issue reports (IRs). BGE used IRs to identify any program weaknesses. Four IRs were generated by the Chemistry staff involving improvement of the effluent control programs. The Audit team followed the corrective actions of IRs and documented them in Audit No. S-95-3-2, for followup and tracking purposes.
Based on the above review, the inspector determined that the scope and technical depth of the audits was sufficient for assessing quality of the radioactive liquid and gaseous effluent control programs.

## F8 Miscellaneous Fire Protection Issues

<u>(Closed) VIO 50-317 and 318/95-06-03</u>: Failure to maintain fire and safety technician qualifications to perform surveillance testing.

The inspectors reviewed BGE's corrective actions for a failure to maintain and adequately document fire and safety technician (FST) qualifications in accordance with the BGE Test and Inspection Personnel Qualification Manual. The Violation was documented in NRC Inspection Report 50-317 and 318/95-06.

In response, BGE developed a "Safety and Fire Protection STP (surveillance test procedure) Performance Improvement Action Plan." The plan included corrective action and evaluation in the areas of training, qualification and certification, procedures, assessments, and work schedule and staffing. The inspectors discussed the plan and status of action items with the Supervisor of the Safety and Fire Protection Unit and other BGE staff.

As part of the action plan, BGE had implemented the Training Maintenance System (TMS) computer program as a supervisory aid to track training, qualification, and certification status of fire and safety technicians. In addition, an on-going self assessment of the fire protection program was initiated. The inspectors also reviewed the TMS report and the most recent quarterly self assessment. The inspectors concluded that BGE actions were appropriate to correct the problem and prevent recurrence. VIO 95-06-03 is closed.

**L1 Review of UFSAR Commitments**

A recent discovery of a licensee operating their facility in a manner contrary to the Updated Final Safety Analysis Report (UFSAR) description highlighted the need for a special focused review that compares plant practices, procedures and/or parameters to the UFSAR descriptions.

While performing the inspections discussed in this report, the inspectors reviewed the applicable portions of the UFSAR that related to the areas inspected. The inspectors verified that the UFSAR wording was consistent with the observed plant practices, procedures and/or parameters.

## V. <u>Management Meetings</u>

**X1 Exit Meeting Summary**

During this inspection, periodic meetings were held with station management to discuss inspection observations and findings. On April 11, 1996, an exit meeting was held to summarize the conclusions of the inspection. During this inspection, a document containing Failure Prevention Inc. proprietary information was provided by BGE for NRC review. No proprietary information was knowingly included in the report from that document. BGE acknowledged the findings presented.

## ATTACHMENT

### PARTIAL LIST OF PERSONS CONTACTED

BGE

P. Katz, Plant General Manager
K. Cellers, Superintendent, Nuclear Maintenance
K. Neitmann, Superintendent, Nuclear Operations
P. Chabot, Manager, Nuclear Engineering
T. Camelleri, Director, Nuclear Regulatory Matters
B. Watson, General Supervisor, Radiation Safety
C. Earls, General Supervisor, Chemistry
C. Mahon, Project Manager, Diesel Generator Project

NRC

L. Doerflein, Branch Chief, Division of Reactor Projects, Region I
E. Kelly, Branch Chief, Division of Reactor Safety, Region I

### INSPECTION PROCEDURES USED

IP 62703: Maintenance Observation
IP 71707: Plant Operations
IP 93702: Prompt Onsite Response to Events at Operating Power Reactors
IP 61726: Surveillance Observations
IP 37550: Engineering
IP 37551: Onsite Engineering
IP 71750: Plant Support Activities

### ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

| | | |
|---|---|---|
| 50-318, 96-001: | LER | Automatic Plant Trip Due to Partial Loss of Offsite Power |

Closed

| | | |
|---|---|---|
| 50-317, 318/95-06-03: | VIO | Failure to maintain fire and safety technician qualifications to perform surveillance testing. |