U.S.NUCLEAR REGULATORY COMMISSION
REGION I

Report Nos.	50-317/94-20; 50-318/94-20
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:	May 29, 1994, through July 2, 1994
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Approved by:	Larry E. Nicholson 7/18/94 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; maintenance; engineering; and plant support.

Results:

See Executive Summary.

EXECUTIVE SUMMARY

Calvert Cliffs Nuclear Power Plant, Units 1 and 2

Inspection Report Nos. 50-317/94-20 and 50-318/94-20

Plant Operations: (Operational Safety Inspection Module 71707, Prompt Onsite Response to Events at Operating Power Reactors Module 93702) Operator response to a Unit 1 trip due to a malfunction of the main turbine control system was appropriate. A safety injection pump keylock switch was not returned to its proper position following surveillance testing due to an inadequate procedure, operators were slow to recognize the switch misposition, and the initial review of the issue by BG&E was not thorough. This issue was unresolved. The onsite safety committee conducted thorough, safety-conscious reviews.

Maintenance: (Maintenance Observations Module 62703, Surveillance Observations Module 61726) There were no significant observations this period.

Engineering: (Module 71707) BG&E acted promptly and with good engineering judgement in responding to a potential tornado-induced common mode failure of the emergency diesel generators. Design review of a temporary alteration installed on the Unit 2 saltwater system was inadequate in that it failed to recognize that the connection points were designated for an emergency contingency.

Plant Support: (Module 71707) An apparently isolated example of poor radiological work practices occurred during valve cleaning.

Safety Assessment/Quality Verification: (71707, Evaluation of Licensee Self-Assessment Capability Module 40500) Initial BG&E review of a mispositioned keylock switch for a safety injection pump was not thorough. BG&E acted promptly and with good engineering judgement in responding to a potential tornado-induced common mode failure of the emergency diesel generators. Design review of a temporary alteration installed on the Unit 2 saltwater system was inadequate in that it failed to recognize that the connection points were designated for an emergency contingency.

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DETAILS

1.0 SUMMARY OF FACILITY ACTIVITIES

Unit 1 began the period in Mode 5 (cold shutdown) for repair of a main turbine journal bearing. BG&E completed repairs and took the unit to Mode 1 (power operation) on June 7 to continue post-refueling outage startup testing. The unit reached full power on June 15. On June 16, the unit tripped when the main turbine stop valves unexpectedly shut during weekly performance testing. BG&E kept the unit in Mode 3 (hot standby) while investigating the problem. The unit returned to full power on June 17.

Unit 2 operated this period at power without significant incident.

2.0 PLANT OPERATIONS

2.1 Operational Safety Verification

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

-- control room
-- primary auxiliary building
-- radiological control point
-- electrical switchgear rooms
-- auxiliary feedwater pump rooms
-- security access point
-- protected area fence
-- intake structure
-- diesel generator 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. Compliance with TS and implementation of appropriate action statements for equipment out of service was inspected. Plant radiation monitoring system indications and plant stack traces were reviewed for unexpected changes. Logs and records were reviewed to determine if entries were accurate and identified equipment status or deficiencies. These records included operating logs, turnover sheets, system safety tags and temporary modifications log. The inspectors also examined the condition of 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 backshifts (evening shifts) and deep backshifts (weekend and midnight shifts). Extended coverage was provided for 21 hours during backshifts and 14 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-118 (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. Unit 1 Reactor Trip

At 1:35 a.m. on June 16, the Unit 1 reactor tripped from 100 percent power due to a malfunction of the main turbine control system. At the time of the trip, operators were performing weekly main turbine stop valve testing (Operating Instruction 43C, "Main Turbine Performance Evaluation Checks," section 6.1, main stop valve test 1-93-1-0-W) that involved the sequential closing of the four stop valves. When the operator released the test push button following the shutting of the No. 3 stop valve, the stop valve was supposed to open. Instead, the other three stop valves shut. The reactor automatically tripped on low steam generator water level.

Plant systems responded as expected to the trip except that steam generator level did not recover with post-trip main feedwater flow. As a result, steam generator water level continued to decrease after the trip and caused an auxiliary feedwater (AFW) actuation due to low water level in the 12 steam generator. Operators recovered steam generator level with AFW, shifted the feed regulating valve bypass valves (FRVBVs) to manual control, and reestablished feed control with main feedwater. Of note was the fact that the main feed pumps did not trip on high discharge pressure following the turbine trip. This had been a continuing problem in the past that BG&E apparently corrected by the digital feedwater system modification installed during the recent Unit 1 refueling outage.

Operator response was prompt and according to established procedures. BG&E notified the NRC as required by 10 CFR 50.72. The post-trip review was thorough.

BG&E found that an air relay on the 12 FRVBV positioner only opened the valve to a post-trip position of 25%, instead of 33%. Maintenance replaced the relay. Preliminary inspection revealed some particulate matter that may have prevented the relay from operating properly. However, BG&E evaluated that even if the valve had opened to the 33% position, an AFW actuation would have occurred due to the circumstances of the trip. During an uncomplicated turbine trip and reactor trip, steam generator level starts at 0 inches. Under those circumstances, main feedwater should recover steam generator level before an AFW actuation. In this event, the closing stop valves caused level shrink phenomenon, which caused a reactor trip at -50 inches in the steam generator. From that level, main feedwater was unable to recover steam generator level before AFW actuated. BG&E verified the evaluation using the simulator.

BG&E conducted extensive troubleshooting with the assistance of the vendor, but was unable to reproduce the trip scenario. On June 17, BG&E started up and paralleled the unit to the grid. Operations satisfactorily conducted main turbine stop valve testing at about 12% power. No abnormalities were seen. Following evaluation, BG&E brought the unit to full power.

System engineering personnel concluded that the most likely cause of the stop valves malfunction was spurious electrical noise or a stuck open dump valve in the electro-hydraulic control (EHC) circuit. The vendor was still conducting troubleshooting at the end of the period, and BG&E expected to conduct follow-on troubleshooting later in July depending on the vendor findings. Based on vendor recommendation, BG&E reduced the periodicity of stop valve testing from weekly to quarterly. The next scheduled testing was in September. Meanwhile, BG&E system engineering was evaluating the plant conditions under which the next testing would be performed, such as reducing power to below 15% to prevent a reactor trip if the turbine is lost, and running an additional EHC pump to prevent a stuck-open dump valve from closing the stop valves. Inspectors concluded that operators responded appropriately to the transient and that BG&E's troubleshooting and corrective actions were reasonable.

2.3 Keylock Switch Mispositioned for Two Days

A Unit 1 operator did not return the 11 low pressure safety injection pump recirculation actuation system (RAS) override keylock switch to its proper position following the completion of a surveillance test. The surveillance test was inadequate in that steps to properly position the keylock were omitted. Operators did not recognize the mispositioned switch (located on a control room panel and clearly visible) for two days. The mispositioned switch increased the vulnerability for losing shutdown cooling due to a spurious RAS signal. Subsequent initial review of the problem by BG&E's Issue Report Review Group (IRRG) was not thorough in that they did not recognize the delay in the identification of the mispositioned switch.

On June 3, 1993, while Unit 1 was in cold shutdown (Mode 5), an operator found the 11 low pressure safety injection (LPSI) pump RAS override keylock switch in the "normal" position. The 11 LPSI pump was providing the motive force for shutdown cooling. Operating Instruction

(OI)-3B, "Shutdown Cooling," required that the override keylock switch for both LPSI pumps to be maintained in "override." This was to prevent a spurious RAS signal from causing LPSI pump trips while on shutdown cooling.

BG&E found that the keylock switch had been positioned in the "normal" position during the performance of Surveillance Test Procedure (STP) O-7A-1, ""A" Train Engineered Safety Feature Logic Monthly Test" performed on June 1, 1994. However, the operators did not reposition the keylock at the end of the surveillance test because the STP lacked steps to reposition the keylock. The STP associated with the "B" logic train did have steps to reposition the keylock switches. Originally, operators tested both logic trains using one STP and steps to reposition the keylock switch followed the completion of the "B" logic test. In November 1990, as part of BG&E's procedure upgrade project, the STP was split into two STPs, one for each logic train. However, the procedure writers did not include steps for repositioning the keylock switches for the "A" logic test. BG&E did not recognize this omission during subsequent procedure reviews. In addition operators did not identify the problem during testing because the "B" logic test had normally been promptly performed following the completing of the "A" logic test. In this instance, the operators tested only the "A" logic train.

The operators documented the above problem in an issue report (IR). The initial screening of the issue report was not thorough. The IRRG did not recognize the operator awareness aspect of the problem and did not highlight the IR as requiring management attention. As a result, the General Supervisor-Nuclear Plant Operations was unaware of the problem when questioned by the inspectors. The Chairman of the IRRG agreed that review of the issue was not comprehensive. This appeared to be an isolated case based on a review of selected recent IRs.

There were no safety consequences because of the mispositioned keylock switch. The 12 LPSI pump was available if the 11 LPSI pump had tripped. In addition, operators would have been able to restart the 11 LPSI pump after placing the keylock switch in its proper position.

BG&E agreed that the surveillance test was inadequate. In addition, Operations management began a review to learn why operators failed to recognize that the keylock switch mispositioning was not identified during shift turnover or control board walkdowns. This problem is Unresolved pending NRC review of BG&E's corrective actions (URI 50-317 and 318/94-02-02).

2.4 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 met. 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. Overall, the level of review and member participation was excellent in fulfilling the POSRC responsibilities. Particularly noteworthy were discussions concerning recent auxiliary feedwater turbine performance problems. Committee members asked probing safetyfocused questions that had not been previously considered by the engineers who were making the POSRC presentation.

3.0 MAINTENANCE

3.1 Maintenance Observation

The inspector reviewed selected maintenance activities to assure that:

- the activity did not violate technical specification limiting conditions for operation and that redundant components were operable;
- required approvals and releases had been obtained prior to commencing work;
- procedures used for the task were adequate and work was within the skills of the trade;
- activities were accomplished by qualified personnel;
- where necessary, radiological and fire preventive controls were adequate and implemented;
- quality verification hold points were established where required and observed; and
- equipment was properly tested and returned to service.

Maintenance activities reviewed included:

MO 29402310	Clean 21 component cooling heat exchanger tubes
MO 29306052	Inspect 21 ECCS pump room cooler duplex strainer
MO 29306123	Replace anodes on 21 ECCS pump room cooler
MO 29105372	Replace and test 2-SW-5205-RV, the 21 ECCS pump room cooler relief valve
MO 29306125	Inspect 21 ECCS pump room cooler channel heads
MO 28805623	Replace spacer for TI 5258 in the 21 ECCS pump room cooler outlet spool piece
MO 09300298	Install freeze seal to replace 0-SFP-127 and 128 in the purification system supply from the SFP cooler

Inspectors also reviewed temporary alteration 1-93-003, including the design and engineering evaluation which supported the freeze seal.

MO 29306069	Calibrate 21 Service Water Heat Exchanger (SRWHX) pressure transmitters
MO 29306041	Clean 21 SRWHX tubes
MO 19208073	Perform CCI-117 troubleshooting during STP O-5-1
MO 19303183	Spent fuel vacuum sipping
MO 29306129	PMs on 21 ECCS system
MO 09302345	Replace No. 12 Emergency Diesel Generator (EDG) indicating tachometer

The work observed was performed safely and in accordance with proper procedures. Inspectors noted that an appropriate level of supervisory attention was given to the work depending on its priority and difficulty.

3.2 Surveillance Observation

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

The following surveillance testing activities were reviewed:

STP O-05-1 11 and 12 AFW pump testing

STP O-89-0 Fire suppression system checks

STP O-73B-2 21 SRW pump performance test

MO 09302345 Post maintenance test 12 EDG to calibrate tachometer

MO 19208030 Supplemental STP-0-73B for Nos. 12 and 13 service water pumps

STP-O-03B-1 No. 12 EDG and 4kV Bus 14 LOCI sequencer test

STP-O-05-2 21 and 22 AFW pump testing

The surveillance testing was performed safely and in accordance with proper procedures.

Inspectors noted that an appropriate level of supervisory attention was given to the testing depending on its sensitivity and difficulty.

4.0 ENGINEERING

4.1 Potential Common Mode Failure of the Emergency Diesel Generators (EDGs)

In early June 1994, while evaluating potential weather-related effects on the new EDG cabling on the auxiliary building roof, BG&E found that all three EDGs housed in the auxiliary building could potentially be rendered inoperable by a tornado. Specifically, the EDG's air inlet and exhaust piping was not designed to withstand 300 mph tornado force winds (a value assured in the accident analysis in Calvert Cliffs' Updated Final Safety Analysis Report (USFAR)). Similar concerns were raised for the control room ventilation equipment also found on the roof.

On June 9, 1994, BG&E performed an operability assessment and concluded that there was reasonable assurance the EDGs would perform their safety function; however, further analysis was needed to decide whether additional protection or compensatory measures would be required. BG&E briefed the NRC on the results of the operability assessment and intended actions via conference call. Pending completion of further analysis, BG&E staged equipment to expeditiously remove any piping damaged by tornado. Twenty-four hour coverage by maintenance personnel trained in the use of this equipment was also provided. On June 15, 1994, analysis showed that the EDG piping would remain functional; however, additional support would be needed to provide full qualification. The Plant Operations Safety Review Committee (POSRC) approved a support modification on June 27, 1994. Implementation was scheduled for July 1994.

The inspectors concluded that BG&E acted promptly and with good engineering judgment in responding to this issue. The operability determinations, taken together, were thorough and well-reasoned. Also, BG&E concluded that a safe shutdown of both units was possible even with a complete loss of control room ventilation cooling. Consequently, BG&E had appropriately assigned a lower priority to returning the ventilation system to its design conditions.

4.2 Inadequate Design Review of a Temporary Alteration

BG&E's design review of a temporary alteration to the Unit 2 salt water system was inadequate. As a result, workers connected a temporary alteration (TA) to a fitting that served as the connection for the safety-related make-up water supply to the Unit 2 service water system. This was the result of process weaknesses. Engineering evaluations associated with this TA did not address the impact of the TA on the operators' ability to use the connection for service water system make-up. Due to the long time delay between TA approval and actual installation, information contained in the engineering evaluation became invalid. Onshift review of the TA just prior to installation did not identify the inaccuracies in the evaluations. The inspectors identified this problem during a tour of the Unit 2 service water room.

In late 1992, BG&E found that the service water systems lacked a safety-related make-up water source (See NRC Special Inspection Report 50-317 and 50-318/93-31). As a result, BG&E initiated several compensatory actions that included staging hoses outside both service water pump rooms. If the installed make-up water sources to the service water system were lost, the hoses were provided to allow operators to promptly connect the affected service water system to a saltwater (SW) header. The connection points for the hoses on the SW headers were via drain line isolation valves 2-SW-1067 and 2-SW-1073. BG&E did not proceduralize the actions necessary to connect these hoses until October 1993, when they revised Operating Instruction (OI)-15 "Service Water System."

On July 26, 1993, the Plant General Manager approved the installation of temporary alteration (TA) 2-93-0036 to the Unit 2 SW system to permit monitoring of the effectiveness of a trial chemical additive (Clamtrol). Part of the temporary alteration included the connection of a corrosion monitor rack assembly to each SW header. The corrosion monitor rack assembly consisted of polyvinyl chloride piping, test coupons, a flow orifice and a corrosion monitor probe. The connection points for the TA were via 2-SW-1067 and 2-SW-1073.

Neither the 10 CFR 50.59 safety evaluation or the engineering evaluation associated with the TA addressed the impact of the TA on the operators' ability to connect the SW system to the service water system. The design engineers who developed the safety and engineering evaluations were not aware that 2-SW-1067 and 2-SW-1073 had been designated as the connection points for the safety-related source of make-up water. There were no engineering process requirements to identify fittings, connection points, etc., that were dedicated for plant contingencies. Due to this lack of awareness, coupled with lack of a timely revision to OI-15, the engineers concluded that no procedure changes would be required.

The lead system engineer did recognize that the TA would be installed at the above locations and concluded that this was not a concern because he felt it was within the "skill of the craft" for the operators to remove the TA in the event that the connections were needed for service water make-up. However, the system engineer never consulted operations department personnel.

On April 25, 1994, maintenance personnel installed the TA following authorization by the Unit 2 control room supervisor and the shift supervisor (SS). Their review of the TA package did not identify that OI-15 required revision to reflect the TA. The SS stated he believed that a procedure change was not required because the engineering evaluation included in the TA package concluded that no procedure changes were needed. This was valid when the form was completed but was no longer true after OI-15 was revised in October 1993. There were no programmatic requirements for additional engineering reviews of TA packages that had not been installed for an extended period following plant manager approval.

There were no safety consequences because of this issue. It appeared that plant operators could have removed the TA in a timely manner if the installed make-up water sources to the service water system were lost. The inspectors did not identify other recent similar issues. However, due to the process weaknesses discussed above, the potential existed for a TA to be installed that may have hindered prompt operator response to plant events. Not withstanding the lack of safety consequences, the design review of the TA was inadequate in that it did not recognize the impact of the TA on plant procedures (OI-15). This lack of an adequate design review constituted a violation of 10 CFR 50, Appendix B, Criterion III (Violation 50-317 and 318/94-20-01).

5.0 PLANT SUPPORT

There were no noteworthy findings in the emergency preparedness, security, chemistry, or fire protection areas.

5.1 Radiological Controls

During a routine tour of the auxiliary building, inspectors noted work being performed without adequate controls to prevent the spread of contamination to radiologically clean areas or personnel. A contract technician had been instructed to clean several valves with packing glands encrusted with boric acid using a trisodium phosphate solution. While performing this task on the 11 low pressure safety injection (LPSI) pump discharge valve, the worker leaned over the postings indicating that the area was radiologically contaminated and sprayed the cleaning solution on the valve. Health physics technicians had previously staged a small drip pan under the valve's packing gland to contain leakage, however backsplash from the cleaning spray reached outside the contaminated area boundary and also wetted the 11 LPSI pump casing insulation and associated piping. At the time, the technician was not wearing protective clothing and some of the backslash appeared to hit him. The inspectors immediately discussed this observation with health physics supervisors. The area around the 11 LPSI pump and the technician were surveyed and no contamination was found. The technician was counselled on proper work practices and clothing and a larger catch basin was installed to adequately contain the backsplash and cleaning residue. Additionally, health physics supervisors reviewed this event with all radiation safety personnel. The inspectors assessed that this example of poor radiological work practices was an isolated instance, as several other valve cleaning evolutions under similar circumstances were properly conducted.

5.2 Housekeeping

The inspectors assessed the control of plant housekeeping in safety related areas. They also examined these areas for potential missile hazards such as gas cylinders that could damage safety significant equipment. General plant housekeeping during the period improved from the last period with the removal outage related material. Overall, housekeeping was good.

6.0 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.

6.1 Preliminary Inspection Findings

An inadequate surveillance test procedure resulted in a keylock switch mispostioning that operators did not recognize for two days. This was an unresolved item as discussed in section 2.3.

The design review for a Unit 2 temporary alteration was inadequate and was a violation of NRC requirements. See section 4.2 for details.

6.2 Attendance at Management Meetings Conducted by Region Based Inspectors

Date	Subject	Inspection Report No.	Reporting Inspector
6/24/1994	EDG Project	50-317/94-22 50-318/94-22	L. Cheung