U.S.NUCLEAR REGULATORY COMMISSION
REGION I

Report Nos.	50-317/94-19; 50-318/94-19
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:	April 17, 1994, through May 28, 1994
Inspectors:	Carl F. Lyon, Acting Senior Resident Inspector Henry K. Lathrop, Resident Inspector
Approved by:	Larry E. Nicholson 6/6/94 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.

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EXECUTIVE SUMMARY

Calvert Cliffs Nuclear Power Plant, Units 1 and 2

Inspection Report Nos. 50-317/94-19 and 50-318/94-19

Plant Operations: (Operational Safety Inspection Module 71707, Prompt Onsite Response to Events at Operating Power Reactors Module 93702) Operator response to a major fault in one of the 13 kV voltage regulators was prompt and carefully considered. The Unit 1 refueling outage was completed safely, despite several late equipment problems that challenged operators to perform several startup and shutdown sequences on Unit 1, while conducting a Unit 2 shutdown and startup for a mini-outage. Operators had not rigorously pursued sedolution of the service water radiation monitor alarms, despite an otherwise aggressive control room alarm reduction program.

Maintenance: (Maintenance Observations Module 62703, Surveillance Observations Module 61726) Troubleshooting of the steam generator feed pump speed oscillations was thorough and methodical. The in-core instrument flange inspection on Unit 2 was thorough and well-coordinated.

Engineering: (Module 71707) BG&E's response to a high pressure safety injection relief valve failure was comprehensive and timely. The operability determination and engineering evaluation following discovery that a pressurizer code safety valve was heavier than analyzed for were prompt and thorough.

Plant Support: (Module 71707) Based on the secondary chemistry performance indicators and historical data, Calvert Cliffs had an aggressive program of chemistry management. Based on lessons learned from a January shutdown, chemistry and operations sections made a concerted effort to coordinate shutdown cooling and purification during the May Unit 2 outage to minimize radiation levels. Gamma meters used to supplement the installed main line steam radiation monitors were a prudent enhancement of monitoring capability. Responsibility for service water radiation monitors was not well understood.

Increased management attention, dedicated monitoring, and the use of the weekly plant general housekeeping report contributed to good control of housekeeping during the refueling outage.

Safety Assessment/Quality Verification: (71707, Evaluation of Licensee Self-Assessment Capability Module 40500) BG&E's conduct of the refueling outage was well-managed with due emphasis on personnel and nuclear safety. The Startup Review Board displayed a strong questioning attitude with a clear focus on nuclear safety.

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DETAILS

1.0 SUMMARY OF FACILITY ACTIVITIES

Unit 1 began the period in Mode 5 (cold shutdown) in a refueling outage. The unit entered Mode 4 (hot shutdown) on April 29 and Mode 3 (hot standby) on April 29. Following rod testing, the unit was cooled down to Mode 5 on May 3 to replace a leaking pressurizer safety valve, 1-RC-200-RV. On May 10, the unit entered Mode 3 to conduct post maintenance testing of 1-RC-200-RV and begin low power physics testing. The reactor was taken critical on May 12. Low power physics testing was completed satisfactorily, but the unit was unable to go to Mode 1 (power operation) on May 14 due to speed oscillations on the steam generator feed pumps (SGFPs). Adjustments were completed on May 18 and Unit 1 was taken to Mode 1 to continue startup testing. The 11 SGFP continued to be unusable due to speed control problems, so reactor power was limited to 65%. On May 26, the unit was taken to Mode 2 and came off the grid to do a balance shot on the main turbine, due to vibrations on one of the main bearings. While returning the turbine to service on May 27, a different main bearing overheated. The unit was taken to Mode 5 on May 28 to repair the damaged bearing.

Unit 2 began the period at full power. Operators shut down the unit on May 16 to begin a 14 day scheduled outage. BG&E completed the outage early and the unit returned to power on May 22.

On May 23, a third 500 kV offsite power line to Calvert Cliffs was put in service. The line ran from Calvert Cliffs to the Potomac Electric Power Company generating station at Chalk Point and completed the grid loop around Washington, D.C.

2.0 PLANT OPERATIONS

2.1 Operational Safety Verification

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

-- control room
-- 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.

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 17 hours during backshifts and 10 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. Voltage Regulator Fault

While conducting tap changer testing on the new voltage regulator between 13 kV bus 11 and 4 kV transformer U-4000-11 on April 24, a fault occurred which opened feeder breakers 252-1101, 1102, and 1103. When breaker 1103 opened, it de-energized 4 kV transformer U-4000-12, which was supplying Unit 2 4kV vital bus 21. As expected, no reactor trip occurred. The 12 emergency diesel generator (EDG) started as designed on the under-voltage signal from the 21 bus, however, operators elected to re-energize the bus from its alternate feeder breaker rather than load it onto the EDG. No other engineered safety feature actuations occurred. One of the two offsite power lines was declared inoperable, and Unit 2 entered the appropriate technical specification limiting condition for operation (LCO) action statement. The NRC was notified in accordance with 10 CFR 50.72.

The loss of 21 bus resulted in the loss of a component cooling water pump, a salt water pump, and a service water pump. Alternates to these were started by operators. The feedwater system operated as expected. Two main turbine intercept valves, 1IL and 3IR, shut for unknown reasons and did not re-open. In accordance with procedure, operators began to lower power on Unit 2 to less than 80%; however, technicians were able to verify the valves' operability and re-opened them. The power decrease was stopped at 95% and the unit returned to full power. U-4000-12 and breaker 1103 were verified to be fault-free and were restored to service, and the Unit 2 electrical lineup was returned to normal. Unit 2 then exited the action statement.

Impact on Unit 1 was minimal, due to the electrical lineup existing for the voltage regulator testing and plant conditions. No loads were being supplied by U-4000-11, so nothing was lost when breaker 1102 opened. Non-vital buses 15 and 16 were lost when breaker 1101 opened, resulting in the loss of the circulating water pumps. These buses were re-energized from alternate sources and the pumps were restored.

Operator response to the event was prompt and in accordance with procedures. The potential consequences of each manipulation of the electrical distribution lineup were carefully considered, given the unknown cause of the event. BG&E immediately returned the voltage regulator bypass switch to the bypass position on U-4000-11. The other two voltage regulators were already in bypass. Testing and work on the voltage regulators was halted and the area was quarantined.

BG&E formed a significant incident finding team (SIFT) to conduct a root cause analysis. In addition, they began an investigation to determine if any common root causes existed with other recent electrical events. Technicians inspected the 1102 voltage regulator tap changer and found it to be undamaged and operating properly. Oil samples indicated that an arc occurred in the main tank. Also, gas analysis showed 4% combustible gases in the main tank. While some gas formation was expected due to normal operation, the 1102 voltage regulator had only undergone 7 tap changes. The 1101 voltage regulator had undergone 98 tap changes during its testing and had only 0.02% combustible gases in the main tank.

Subsequent examination of the main tank revealed a copper dust and black residue in the oil, indicating a possible turn-to-turn fault in the main windings. BG&E returned the 1102 voltage regulator to the factory for further investigation. It was replaced with an onsite spare.

Inspection at the factory by the vendor and BG&E representatives confimed that a failure occurred in the main windings. Following evaluation, the most likely cause was believed to be from foreign material intrusion during manufacture; however, this could not be confirmed since the winding was destroyed. There was no evidence of a generic problem that would have affected the other voltage regulators. BG&E changed the testing methodology to provide earlier detection of potential degrading conditions or arcing inside the voltage regulators.

BG&E also investigated why the 1101 and 1103 breakers opened, since the fault was in the voltage regulator associated with breaker 1102. Extensive testing did not duplicate the event conditions, but BG&E did conclude that the particular ground fault relays used with the voltage regulators were sensitive to high frequency electric pulses, such as those an arc in the high voltage main windings might have produced. BG&E reviewed the design and installation of the relays and reconfigured the ground fault relays to a sequential tripping scheme to minimize unnecessary bus trips. They continued to investigate potential methods of desensitizing the relays to high frequency electric pulses. In addition, BG&E completed a modification that re-configured the control signal to the voltage regulator automatic controller from the internal power transformer to the external power transformer, to desensitize the controller to third harmonic voltage levels.

The SIFT found that the six intercept valves on the Unit 2 main turbine shut during the event as expected due to the fast valving sequence. The sequence was designed to limit turbine overspeeding during partial loss of load. However, two of the valves did not re-open as expected until the valve actuators were mechanically agitated by instrument maintenance technicians. After investigation and discussion with the vendor, system engineers concluded that the most likely cause was galling of the seat on the dual seat main dump valve of the actuators. BG&E periodically conducted actuator rebuilding in accordance with the vendor technical manuals, but there was no mention of possible seat galling over time in the manuals. BG&E added the phenomena to their actuator inspection program and intended to inspect the actuator blocks and perform a system flush during the next refueling outage. In addition, they put an additional filter rig on the electro-hydraulic control oil system as an enhancement to prevent foreign material interference with valve operation.

Inspectors monitored the onsite voltage regulator inspection and troubleshooting activities and attended POSRC discussions of the incident. The investigation was extensive and methodical. Following discussion of the preliminary results and planned safety precautions with the NRC, BG&E completed voltage regulator installation and testing with no further events. The third offsite 500 kV transmission line was subsequently tested and placed in service without incident. The SIFT had not completed their report at the end of the period. The report will be reviewed by inspectors during routine follow-up. BG&E documented the event in Licensee Event Report 94-005.

2.3 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. Overall, the level of review and member participation was satisfactory in fulfilling the POSRC responsibilities.

2.4 Offsite Safety Review Committee

Portions of the Offsite Safety Review Committee (OSSRC) meeting on May 25 were attended by the inspectors. The OSSRC composition and agenda were in compliance with the requirements of TS 6.5.4. The agenda included a review of plant status and significant safety issues and proposed changes to the operating license. The committee discussed high and low points of the Unit 1 refueling outage, including the failure to meet the radiation dose goal for the third year in a row. A good questioning attitude and safety perspective were observed, and several items were referred to the plant staff for additional information before resolution. Members discussed concerns in the areas of foreign material exclusion management, reactivity management, and rigging. Overall, the level of review and member participation was satisfactory to fulfill the OSSRC responsibilities.

2.5 Unit 1 Refueling Outage

Unit 1 completed its twelfth refueling outage on May 18 when the main generator was synchronized to the grid. The inspectors concluded that, overall, BG&E's conduct of the outage was well-managed with due emphasis on personnel and nuclear safety, resulting in no lost time injuries or challenges to shutdown reactor safety. Additionally, operations personnel performance during several startup and shutdown sequences due to equipment problems was excellent and event-free. An assessment of select outage-related activities is detailed as follows:

- Saltwater Piping Replacement - BG&E replaced the bulk of the saltwater piping in the Unit 1 turbine and auxiliary buildings. The replacement was well-planned and implemented ahead of schedule with relatively little impact on other work.

- Nuclear Fuel Activities - The inspectors noted the extensive management attention given to this area. Fuel movement controls were strengthened. Recent fuel-related incidents at other sites were reviewed with all concerned personnel as to potential difficulties which could be experienced as well as the need for a heightened questioning attitude, procedure compliance, and attention to detail. The inspectors observed that refueling personnel performed professionally and in accordance with their procedures. These measures, in addition to controls already in place, were effective, as indicated by the incident-free fuel off-load and subsequent reload.

- Startup Review Board (SURB) Activities - The SURB was composed of the plant department managers and provided management oversight of the plant's readiness to restart. The board reviewed current plant material condition, status of modification implementation and package closeout, mode change restraints, maintenance order status, and outstanding safety issues/concerns. The inspectors attended both SURB meetings associated with the Unit 1 restart and determined that board members displayed a strong questioning attitude with a clear focus on nuclear safety. Board members performed a number of area inspections to independently verify restart readiness, with the results discussed at the board meetings.

- BG&E's implementation of their shutdown safety program was excellent. Despite a demanding outage schedule that accommodated extensive onsite and offsite electrical work, there were no shutdown safety-related incidents during the outage. The inspectors assessed that BG&E's shutdown safety program continued to be a strength.

- BG&E exceeded the radiation dose goal for the outage for the third year in a row. They concluded that this was due in large part to increased work scope on the steam generator eddy current testing, replacement of the 12A RCP motor, and the pressurizer heater sleeve nickel plating and heater replacement, and rework on the refueling pool neutron shield and a failed pressurizer heater. BG&E estimated that increased work scope and rework accounted for about 45 man-rem. Nevertheless, BG&E continued to aggressively pursue methods to reduce personnel exposure, as evidenced by the use of an improved nozzle dam design for the steam generators and retooling to improve incore instrument (ICI) replacement. For example, last year the ICI replacement on Unit 2 took three days to complete and 18 of the ICIs were broken during installation. This year, the replacement took eight hours, no ICIs were broken, and 8 man-rem were saved.

- The inspectors noted substantial improvement in BG&E's control of foreign material in the spent fuel pool area. However, problems with foreign material intrusion continued in other areas, for example, two emergency diesel generator (EDG) air start check valves, the 11 EDG crankcase and the 12 auxiliary feedwater (AFW) pump. The inspectors concluded that BG&E's corrective actions in this area were not yet fully effective. BG&E management felt that, while improvement had been made in the primary systems and spent fuel pool areas, continued emphasis was required in the cooling water systems, hydraulic systems, and air systems.

- Three significant equipment problems (12A RCP motor, pressurizer code safety valve leakage, and steam generator feed pump speed oscillations) occurred late in the outage and resulted in outage completion four days beyond the 95 day goal. Until these problems occurred, BG&E was actually over a week ahead of schedule. However, in each case the inspectors noted very good cooperation and communications between all groups involved. Management's attention to these issues was prompt and conservative. As a result of the experience, however, BG&E was investigating methods of improving troubleshooting to make it more timely while retaining effectiveness.

- As a result of lessons learned from personnel errors that led to events that marred the end of the last two refueling outages, operations management implemented a number of measures during the transition from outage to operating mode to focus on event-free operation. These measures included reiterating management's expectations regarding event-free operation, minimizing new personnel on shift, implementing a new "OPS gold card" self-assessment system to heighten operator awareness of good and poor practices, and utilizing cross-shift observations. The inspectors assessed that these additional measures were effective in helping Unit 1 operators perform an event-free startup. Throughout the outage, the inspectors noted that operations personnel in the control room maintained a professional and safety-focused attitude. Particular attention was placed on preventing crew overload during testing, and preventing interference with Unit 2.

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.

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. Maintenance activities reviewed included:

MO 19400894	Replace 1-SW-5210-CV
MO 19400896	Replace 1-SW-5150-CV
MO 29402354	Clean ICI connectors inside reactor vessel shroud
MO 29304745	Replace fan VU-19A and fire damper with new safety-related fan in Unit 2 service water room

Workers replacing the fan and fire damper in the Unit 2 service water room were knowledgeable of the technical specification requirements in effect during the work.

MO 29402475 Establish freeze seal for 2-SI-134, the 22B LPSI loop check valve

Operators and personnel operating the freeze seal equipment were knowledgeable of its function and limitations and the contingency plans in effect.

MO various 21 EDG preventive maintenance and testing

MO 29306038 Cleaning 22 service water heat exchanger (SRWHX)

Foreign material control and accountability during 22 SRWHX cleaning was good.

In addition, inspectors observed portions of the troubleshooting and repairs to the Unit 1 steam generator feed pump (SGFP) speed control systems, and inspection of the Unit 2 in-core instrumentation (ICI) flanges. Troubleshooting of the SGFPs followed a methodical plan using Kepner-Tregoe techniques and vendor consultation. The 12 SGFP operated satisfactorily following adjustment of the fulcrum point on the pilot valve feedback mechanism and replacement of the control oil pilot valve springs to adjust the spring constant. The 11 SGFP speed control was not functioning properly at the end of the period, but ongoing troubleshooting later revealed the most likely problem to be an improperly drilled drain port in the control oil pilot valve lower bushing during the modification implementation. BG&E investigation into the problem was continuing.

The Unit 2 ICI flanges inspection was thorough and well-coordinated with radiation safety, systems engineering, and in-service inspection personnel. Camera and video equipment were used to obtain a permanent record of the condition of the flanges for future reference.

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 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. The following surveillance testing activities were reviewed:

STP O-5A-2 AFW System Quarterly Test

STP O-9-2 AFW Actuation System Monthly Logic Test

PSTPs 13 and 2 Pre-Startup Test Procedures

3.3 12A Reactor Coolant Pump Motor Damage

The 12A reactor coolant pump (RCP) motor failed while being started on April 8. The RCP had not been worked on during the outage. It was being started to sweep air out of the steam generator tubes. The motor failure did not cause an operational transient. When the operator in the control room took the RCP handswitch to the start position, observers in the pump bay saw a fireball exit the pump motor. The RCP breaker tripped after about 10 seconds. Megger readings on the motor taken on March 31 had been satisfactory. Megger readings taken after the event indicated the motor was damaged. Breakaway torque readings indicated the pump was not bound.

BG&E removed the motor from containment for inspection, which revealed extensive burn damage to one of the main phase line cables. There was no evidence of foreign material intrusion. BG&E's root cause analysis concluded that the most probable cause of the event was loose blocking between the phase cables. As a result, the stresses during starting caused mechanical motion of the cables, which loosened a cable connection. The loose cable connection resulted in high resistance and high heat at that point. Finally, the cable connection failed resulting in a phase to phase short. An independent contractor concurred in the analysis following evaluation of the physical evidence.

BG&E used the 12A upper bracket and rotor assembly with the spare RCP stator to build a replacement motor. Following satisfactory testing, BG&E returned the motor to service without incident on April 29.

BG&E and the inspectors reviewed the operating history of the RCPs to evaluate the risk to the other pumps. BG&E has been replacing a RCP every refueling outage since purchasing a spare motor in 1980. The 12A RCP was swapped out in 1987. Vendor reports of the stator mechanical condition during the last overhaul of the motors with the longest operating histories were good. BG&E had one previous RCP failure, in 1987, when an end turn failed on a motor that had operated for 13 years.

The highest risk from the failure mechanism on 12A RCP occurred during pump start. Inspectors monitored the root cause investigation and discussed with operators and system engineers the risk to various RCPs during pump start based on pump operating history. There was no reliable way to assess the blocking condition of the motors without visual inspection. These inspections would require their removal from containment. After evaluation, BG&E decided to restart without additional motor inspection and did so without incident. Since the greatest risk to the motor was during starting, there was no safety significance of a failure to the plant due to the plant's shutdown condition. Once started, there was reduced risk of motor failure due to the blocking condition.

To prevent recurrence, BG&E was considering enhancing their motor overhauls to include a motor rewind. They were also considering various electrical testing that would give increased confidence in the insulation condition of the motors. BG&E's investigation was satisfactory and the recognition of increased pump failure risk during pump start was reasonable.

4.0 ENGINEERING

4.1 10 CFR 21 Report Concerning Nuclear Service Connectors

BG&E received written notification from Conax Buffalo regarding a potential defect in certain models of their nuclear service connectors (NSCs) used in quick disconnect applications. The defect was a noisy electrical resistance for some NSC circuits, which could pose problems for applications which are sensitive to fluctuations in electrical resistance. BG&E investigated and found that they had purchased two of the subject NSCs in 1984 for use in resistance temperature detectors, but they were never certified as safety-related, never calibrated, and never installed or used. The two NSCs were segregated to prevent future use. Inspectors assessed that BG&E's investigation was satisfactory to address the issue.

4.2 High Pressure Safety Injection (HPSI) Relief Valve Failure

On May 11, while running the 11 HPSI pump on minimum flow, the auxiliary HPSI header thermal relief valve, 1-RV-6302, lifted and failed to reseat. Efforts to reseat the valve were unsuccessful and BG&E subsequently replaced it. Inspectors discussed the issue of HPSI system operability with BG&E engineering and operations personnel and reviewed the operability evaluation. The evaluation was detailed and comprehensive and provided an adequate basis for the determination that the HPSI system was operable with the defective relief valve. BG&E was conducting an investigation into the cause of this specific failure and more generally into the issue of safety-related relief valve reliability. Inspectors assessed that BG&E's response to the event and its potential consequences was appropriate and timely.

4.3 Unit 1 Main Generator Differential Ground Fault

Inspectors conducted routine follow-up of BG&E's root cause analysis of the inadvertent opening of 500 kV breakers 552-22 and 23. The event was documented in NRC Inspection Report 50-317 and 318/94-10, section 4.2. The most probable cause was a stray ground current that entered the protection circuit through the common ground at one of the control panels. Testing demonstrated that with the common ground removed, a ground current could not enter the differential protection circuit. Inspectors assessed that the analysis and troubleshooting were thorough and that the corrective actions to prevent recurrence were reasonable.

4.4 Pressurizer Code Safety Valve Leakage

BG&E conducted extensive troubleshooting on pressurizer code safety valve 1-RC-200-RV, which had been replaced during the outage and began leaking during plant heatup in Mode 3. BG&E cooled down and replaced the valve, but the replacement also leaked upon heatup. The leakrates were approximately 17-30 gpm. BG&E finally determined that a pair of sway struts supporting the valve discharge piping were slightly out of alignment. This placed a load on the discharge nozzle and acted to twist the valve and seat. Following realignment of the struts, the valve tested satisfactorily.

While troubleshooting 1-RC-200-RV, BG&E discovered that two different style valves were being used as pressurizer code safety valves, one with a cast body and one with a forged body. The valves were identical with the exception of weight and minor dimensional differences. The cast valves weighed about 500 pounds and the forged valves weighed about 750 pounds. BG&E had purchased three of each valve during new construction and had replaced them indiscriminately; however, an engineering analysis was available only for the lighter valve. BG&E immediately performed an operability determination for Unit 2 and began an engineering analysis. The analysis demonstrated that all deadweight, thermal, and seismic code allowable stress limits were met for the heavier valves. Inspectors reviewed the operability determination and the engineering evaluation and discussed the issue with engineering and operations supervisors. BG&E also began an investigation to determine the new construction interface that caused the problem, and to look at generic implications for other components. Inspectors assessed that BG&E's response to the issue was prompt and thorough.

5.0 PLANT SUPPORT

There were no significant findings in the areas of radiation safety, security, fire protection, or emergency preparedness.

5.1 Plant Chemistry

a. Chemistry Performance Indicator

Inspectors discussed the Calvert Cliffs secondary chemistry performance indicators (CPI) with the General Supervisor-Chemistry to understand differences between the Calvert Cliffs CPI and the industry mean indicators. Calvert Cliffs goals for chloride, sulfate, and iron were more restrictive than standard industry goals, and the sodium goal was the same. Calvert Cliffs did not have a copper goal, because it is an all-ferrous plant, but they had retained the dissolved oxygen goal as a monitor for oxygen transport to the steam generators.

Calvert Cliffs goals were based on achievability and a desired ratio to achieve a neutral to slightly acidic chemistry, for maximum corrosion control. The Calvert Cliffs CPI was counted as a secondary business function, which made it a priority of BG&E management and indicated its importance to the company. When translated into standard industry numbers, the Calvert Cliffs goals were more rigorous. Review of historical data showed that Calvert Cliffs was routinely in the top quartile of the industry for chemistry. Based on the CPI goals and historical data, inspectors concluded that Calvert Cliffs had an aggressive program of chemistry management.

b. Shutdown Cooling System Radiation Levels

Inspectors reviewed an apparent elevation in general area radiation levels in portions of the auxiliary building as a potential ALARA concern. Radiation levels rose significantly following the Unit 2 shutdown in January. Due to circumstances surrounding the shutdown and a lack of communication between operations and chemistry personnel, purification was not aligned to the unit after it was placed on shutdown cooling (SDC). The resultant crud burst was not cleaned up and activity levels remained elevated in the SDC piping. Since January, natural decay had lowered the activity levels in the piping, but some areas of the ECCS pump rooms were still posted as high radiation areas. Inspectors discussed the current status with radiation safety, chemistry, and operations supervisors and found that the more restrictive postings were a result of the new 10 CFR 20 regulations. Review of historical data showed that actual radiation levels following natural decay were not elevated. Inspectors also found that a concerted effort was made by operations and chemistry personnel to maximize purification flow during the recent May Unit 2 outage to minimize residual activity levels. Trend data following SDC initiation showed that the effort was largely successful. The General Supervisor-Chemistry noted that it may not always be possible to reduce radiation levels to as low as desirable due to operational requirements. As a result of lessons learned from the January experience, however, BG&E management would be able to make a conscious decision to accept the consequences of elevated radiation levels, if necessary. Inspectors assessed that BG&E had adequately addressed the issue.

c. Main Steam Line Radiation Monitors

During tours, inspectors noted non-intrusive gamma meters at the main steam line penetrations in the turbine building. These monitors were put in place to provide a quick method of qualitatively determining the affected steam generator during a major tube leak or tube rupture event. The use of the meters was controlled by a lab shop memorandum. Inspectors reviewed the memorandum and discussed the meters with chemistry and operations personnel. BG&E was proceduralizing the use of the meters to replace the memorandum. Their intention, however, was to eventually purchase new nitrogen-16 radiation monitors to replace the current main steam line radiation monitors. Inspectors assessed that the temporary meters were a prudent enhancement of monitoring capability.

d. Service Water Radiation Monitors

During tours, inspectors noted that the service water (SRW) radiation meters in the control room and the local alarms at the monitors in the auxiliary building were in alarm. The purpose of these monitors was to detect increased activity levels in the SRW system, such as from a spent fuel pool heat exchanger leak. Operators stated that the monitors were in alarm due to elevated general area radiation levels from the shutdown cooling (SDC) system piping. Alarm response manual actions had been followed by the operators. These monitors had a normal alarm setpoint and a higher alarm setpoint when SDC was in operation. After SDC was secured, however, the monitors remained in alarm. No action was taken to investigate the situation for about two weeks. Inspectors assessed that operators had not rigorously pursued resolution of the alarms. This was not typical of operator performance. Additionally, following questioning by inspectors, the General Supervisor-Chemistry discovered that no section claimed ownership responsibility for the monitors performance. As corrective action, chemistry section assumed responsibility for all process radiation monitors and radiation safety section assumed responsibility for all area radiation monitors. Lead blankets were placed around the SRW monitors to shield them until general area radiation returned to normal levels. After shielding, the monitor alarms cleared.

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 or scaffolding that could damage safety significant equipment. General plant housekeeping during the period was good. Inspectors noted extra effort by BG&E to restore the plant to operating condition following the Unit 1 refueling outage. Outage-related equipment was expeditiously removed to storage and a concerted clean-up was conducted that had good results. Inspectors concluded that BG&E's effort to control housekeeping during the outage was generally successful. Increased management attention, dedicated monitoring, and the use of the weekly plant general housekeeping report contributed to the success.

6.0 REVIEW OF WRITTEN REPORTS

The inspectors reviewed LERs and other reports submitted to the NRC to verify that the details of the events were clearly reported, including accuracy of the description of cause and adequacy of corrective action. The inspector determined whether further information was required from the licensee, whether generic implications were indicated, and whether the event warranted onsite followup. The following LERs were reviewed:

Unit 1:

LER 94-003 Pressurizer Heater Sleeve Cracking

The issue was the subject of extensive discussion between BG&E, NRR and Region I management, due to the circumferential cracking found in heater sleeve FF-1. Following metallurgical examination, BG&E concluded that primary water stress corrosion cracking was the most probable cracking mechanism. A search of fabrication records revealed that abusive machining during construction was the probable source of the stress in the sleeve.

The LER was an accurate summation of the issue. In addition to sleeves B-3 and FF-1, sleeve CC-1 was plugged. The heater in that location failed during testing after heatup. Apparently, a pinhole leak developed which grounded the heater and caused swelling of the magnesium oxide internals. The heater could not be removed, so its internals were drilled out, the top of the heater was perforated, and the sleeve was plugged with the heater in place. Inspectors assessed that BG&E evaluated the issue comprehensively and addressed it according to proper procedures.

LER 94-004 Excessive Corrosion of Incore Instrumentation Flange Components

The issue was documented in NRC Inspection Reports 50-317 and 318/94-09 and 94-10 and is an unresolved item (UNR 94-09-01).

Units 1 and 2:

LER 94-005 Partial Loss of Offsite Power Caused by a 13.8 kV Voltage Regulator Fault

The event is documented in section 2.2 above. The LER was satisfactory.

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

7.0 FOLLOWUP OF PREVIOUS INSPECTION FINDINGS

7.1 (Updated) Unresolved Item 50-317 and 318/94-09-01

The item involved the discovery of significant degradation of the fasteners on a Unit 1 in-core instrument flange. BG&E implemented a modification on Unit 2 in the Spring of 1993 to correct the flange leakage problem. As mentioned in section 3.1, BG&E inspected the Unit 2 flanges this period and found no evidence of leakage. The flange condition was independently verified by the inspectors. A meeting was scheduled between BG&E and the NRC on June 8, 1994, at the Region I office to discuss the results of BG&E's investigation into the issue.

8.0 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.

8.1 Attendance at Management Meetings Conducted by Region Based Inspectors

Date	Subject	Inspection Report No.	Reporting Inspector
4/22/1994	MOVs	50-317/94-17 50-318/94-17	M. Buckley
4/29/1994	Outage RadCon	50-317/94-18 50-318/94-18	J. Furia
4/29/1994	OL Exams	50-317/94-16 50-318/94-16	J. Prell