U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Docket/ReportNos.: 50-317/87-27
50-318/87-28

License Nos.: DPR-53
DPR-69

Licensee: Baltimore Gas and Electric Company

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

Inspection At: Lusby, Maryland

Dates: November 21 - December 31, 1987

Inspectors: T. Foley, Senior Resident Inspector
D. Trimble, Resident Inspector

Approved By: Lowell E. Tripp 2-8-88
Lowell E. Tripp, Chief Date
Reactor Projects Section No. 3A

Summary: November 21 - December 31, 1987: Inspection Report Numbers 50-317/87-27, 50-318/87-28

Areas Inspected: (1) facility activities, (2) routine inspections, (3) operational events, (4) maintenance, (5) surveillance, (6) Licensee Event Reports, (7) radiological controls, (8) physical security, (9) NRC Compliance Bulletin 87-02, and (10) reports to the NRC.

Inspection hours totalled 208 hours.

Results: No violations were identified. Concerns were identified regarding the operation of the atmospheric steam dump valves (Details Section 4.0).

DETAILS

Within this report period, interviews and discussions were conducted with various licensee personnel, including reactor operators, maintenance and surveillance technicians and the licensee's management staff.

1. Summary of Facility Activities

Unit 1

The unit entered the period escalating in power from a planned maintenance outage conducted on November 20 which was necessary to reconnect the U-25000-12 transformer which was previously damaged by arcing caused by salt, snow and wind conditions on November 11. The unit remained at 100% power through the rest of the period except for minor temporary reductions in power due to corrective and preventive maintenance activities.

Unit 2

The unit entered the period at 100% power but was manually scrammed according to procedures on November 22 due to dropping two control element assemblies to the "full in" positions. The unit returned to power the same day.

On December 7, power was reduced to 30% in order to attempt to repair a steam leak on spray valve CV-100F; however, the repair was unsuccessful. Full power operation resumed. On December 21, the unit automatically tripped due to a failure of the permanent magnetic generator (PMG). Repairs were expected to take several days due to parts delays, however, the unit returned to power on December 23 when parts were located in the on-site warehouse. The unit continued full power operations throughout the rest of the period.

2. Review of Plant Operation - Routine Inspections

a. Daily Inspection

During routine facility tours, the following were checked: manning, access control, adherence to procedures and LCO's, instrumentation, recorder traces, protective systems, control rod positions, containment temperature and pressure, control room annunciators, radiation monitors, effluent monitoring, emergency power source operability, control room logs, shift supervisor logs, tagout logs, and operating orders.

No unacceptable conditions were noted.

b. System Alignment Inspection

Operating confirmation was made of selected piping system trains. Accessible valve positions and status were examined. Power supply and breaker alignment were checked. Visual inspection of major components was performed. Operability of instruments essential to system performance was assessed. The following systems were checked:

-- Steam Dump and Bypass System, Units 1 and 2 checked on December 29, 1987

-- Auxiliary Feed Water System, Unit 2 checked on November 25, 1987

No unacceptable conditions were noted.

c. Biweekly and Other Inspections

During plant tours, the inspectors observed shift turnovers; boric acid tank samples and tank levels were compared to the Technical Specifications; and the use of radiation work permits and Health Physics procedures were reviewed. Area radiation and air monitor use and operational status was reviewed. Plant housekeeping and cleanliness were evaluated. Verification of several tagouts indicated the action was properly conducted.

Attendance at Safety Committee Meetings

The inspectors attended a meeting of the Plant Operations and Safety Review Committee (POSRC) on December 4, and the Off-Site Safety Review Committee (OSSRC) on December 10. No deficiencies were identified. The inspectors made the following observations. The POSRC's use of the facilitator concept appeared to effectively encourage participation in discussions by a larger number of committee members. The Manager, Nuclear Operations listened to the discussions and allowed the committee to independently reach its own conclusions on the various issues on the agenda. This was viewed by the NRC as an improvement in committee operations.

The chairmanship of the OSSRC was transferred from an on-site manager to a company manager outside the Nuclear Operations Department. This was a positive step by the licensee to strengthen the role/representation of members who are not involved in plant activities on a day-to-day basis and who, therefore, should be able to offer fresh insights and independent perspective to the committee.

High Energy Pipe Rupture Protection

Section 10A.4.2 of the Updated FSAR regarding high energy pipe rupture describes a requirement for encapsulation of a Unit 1 high level dump line from #16B feedwater heater for the length of pipe adjacent to the auxiliary feedwater (AFW) pump room. Additionally, the FSAR drawing (Figure 10A.4-6) indicates that two pipe whip restraints are required for that section of line. Licensee engineers noted that the encapsulation and restraints were not installed in the plant. The licensee contacted the architectural engineer (AE). At the close of the inspection period the AE indicated that the need for encapsulation and pipe whip restraints had been eliminated by a subsequent system design change and that the FSAR had not been changed to reflect this modification. The licensee stated that this information needed to be verified. The inspector expressed concern that if the licensee's investigation ultimately shows that the encapsulation and whip restraints should be installed, then additional checks of other areas requiring special measures for high energy line breaks should be inspected. The licensee acknowledged that such inspections would be appropriate.

No unacceptable conditions were noted.

3. Operational Events

Plant Trips

-- On November 22, during the performance of surveillance testing of control element assembles (CEAs) as required by Technical Specification 4.1.3.1.2, one CEA inadvertently dropped. This placed the licensee in Action Statement 3.1.3.1(g) which requires restoring the CEA to an operable status or be in Hot Standby within the next 6 hours. The licensee subsequently had Instrument and Control technicians troubleshoot the dropped CEA. During this troubleshooting a second CEA dropped. Because both rods were in the controlling group with relatively high rod worths, the licensee's procedure required operators to scram the reactor. At 3:25 a.m. operators manually scrammed the Unit 1 reactor from 77% power.

Further investigation revealed that an Instrument and Control technician was called in to work at 2:00 a.m. During the performance of the troubleshooting procedure, the technician removed the adjacent power supply module, located only inches away from the correct power supply module of the rod which had already dropped. This error caused the second CEA to drop. The licensee then manually tripped the unit as required by procedure. Subsequently, the correct power

supply was replaced and the unit returned to power operations at 5:45 p.m. on November 22. A critique of this event was held by the Instrument and Controls supervisor who determined that the corrective action should be to place mechanical interlocks on the various modules to prohibit any two adjacent CEA modules of different control rods from being withdrawn simultaneously. This action apparently will prohibit future errors of this nature.

-- At 6:10 p.m. on December 21, 1987, the Unit 2 reactor tripped due to a loss of load. All plant equipment operated as designed except for #22 atmospheric steam dump which stuck open. (The dump was subsequently shut manually.) The loss of load condition was caused by the opening of the generator output breaker which tripped due to a ground fault on the permanent magnet generator (PMG) stator windings. The fault in the PMG was apparently due to a misalignment between the rotor and stator which led to mechanical contact between these components.

A spare stator was located and the unit returned to power operation on December 23. The atmospheric dump valve (ADV) failure was attributed to two causes. An air leak resulting from a bad gasket caused the positioner to fail. Secondly, a roll pin which normally secures an internal pilot valve plug to the valve stem sheared and allowed the plug to disengage from the valve stem. This prevented the valve from being fully closed. Licensee actions related to this and other ADV problems are described in Section 4 of this report.

4. Plant Maintenance

The inspector observed and reviewed maintenance and problem investigation activities to verify compliance with regulations, administrative and maintenance procedures, codes and standards, proper QA/QC involvement, safety tag use, equipment alignment, jumper use, personnel qualifications, radiological controls for worker protection, fire protection, retest requirements, and reportability per Technical Specifications. The following activities were included:

-- Unit 2 Permanent Magnet Generator repair on December 22, 1987

-- Replacement of Diesel Generator #12 Air Compressor After-cooler checked on December 30, 1987

Atmospheric Dump Valve (ADV) Performance Problems

As described in Section 3 above, one failure of ADV's occurred December 21, 1987. An earlier ADV failure occurred on November 11, 1987 (#11ADV). Following the first failure, the licensee conducted a study of ADV maintenance history since January 1985 which highlighted several

problems. An increasing trend was seen in valve positioner maintenance. The majority of maintenance orders (MO's) documenting valve positioner failures involved failure mechanisms that rendered the valves inoperable from the control room. On occasion, the failures resulted in a valve sticking in the mid-position which can cause a cooldown transient on the reactor coolant system (RCS); e.g., #21 ADV on Unit 2 stuck open following a reactor trip on April 25, 1985 (LER 318/85-01). Positioner failures were primarily caused by degraded gaskets (perhaps due to the high temperature environment in which the positions are located) and loose/ misaligned internal feedback linkages.

The second most significant failure mode was actuator failures (predominantly due to the diaphragm failures) which can render the ADV's inoperable.

The licensee found that their preventive maintenance (PM) program does not adequately address the above components.

The November 11, 1987, sticking open of #11 ADV on Unit 1 was due to physical binding between an adjustment nut on the stem of the valve and the gland follower nuts. The adjusting nut had loosened and backed down the valve stem. The licensee had determined that the adjusting nut is not needed and should not have been installed on the ADV's. Such an adjusting nut is required, however, on the larger turbine bypass valves which are very similar in design to the ADV's and are produced by the same manufacturer. The strong similarity of the ADV's to the turbine bypass valves may explain why the maintenance group may have installed the adjusting nut on the ADV's. During the week of December 28, 1987, the inspector asked if the licensee had inspected the other ADV's for susceptibility for a similar problem. The systems engineer indicated that they intended to check the other ADV's, however, that work had not yet been performed. Following the close of the inspection period, those inspections were performed and showed that the only other ADV with an adjusting nut was the second ADV on Unit 1 (#12 ADV). The nut was found to be tight. At the writing of this report, the adjusting nuts were still installed on the Unit 1 ADV's (the nut on #11 valve had been returned to its original position and "staked" in place).

Because of the similarity to the ADV's, the inspector examined the turbine bypass valves and pointed out three potential problems to the licensee. The adjusting nut on valve #1-MS-3944 CV on Unit 1 was loose and had backed down the stem several turns. Unit 1 valve #1-MS-3942 CV had a second (extra) nut on the stem, the presence of which did not appear to be in accordance with valve design. The system engineer stated he was aware of these problems and corrective action was planned. Finally, the inspector noted that "live loading" (Belleville washers) had been added to some of the valves thus raising the relative position of the gland follower nuts. The inspector asked if this new configuration had been reviewed to ensure that binding with the adjusting nuts on the stems would not occur. The engineer indicated that this had not been considered but should be reviewed.

The matter of the ADV's is unresolved pending determination of the adequacy and promptness of licensee actions to resolve the above valve performance problems (318/87-28-01).

5. Surveillance

The inspector observed parts of tests to assess performance in accordance with approved procedures and LCO's, test results (if completed), removal and restoration of equipment, and deficiency review and resolution.

Auxiliary Feed Water Pump Speed Oscillation

Inspection Report 317/87-23;318/87-25, Section 3, describes recent problems experienced by the licensee with the speed control of the steam drive auxiliary feed water pumps (AFWP). During surveillance testing of the Unit 2 AFWP's on November 25, the #21 pump, the on-service pump, initially tested satisfactorily. Standby pump #22, however, exhibited significant speed oscillations and required operator intervention (by means of manual throttling of the trip valve) to prevent possible over-speed trip. The governor for that pump had the stiffer (26-1/4 pound) buffer springs installed at the time. During the test of #22 pump, the #21 pump was spinning at low speed due to steam leakage by its manual steam isolation valve. For an unknown reason, its trip valve tripped. The #21 pump was again tested and ran satisfactorily.

Because of continued instability during subsequent testing, the governor for #22 AFWP and the associated linkage plates were replaced. Four tests, 12 hours apart, were then satisfactorily conducted of #22 AFWP (3 from on-service line up and one from standby). The inspector asked the licensee to consider a test of the #22 pump after 24 hours in the on-service line up which would be more representative of cold system conditions. He also asked that another test of #21 AFWP be conducted, since it had been tested only once since it tripped from a low speed condition. The licensee agreed to perform these tests and the tests were satisfactory.

As an observation, the licensee stated that even following the installation of the stiffer buffer springs on all AFWP governors, they have noted that the standby pumps have a higher sensitivity to speed oscillations than do the on-service pumps. They have modified their procedure for start-up of a standby pump to include manual throttling of the trip valve and draining the steam line and turbine casing at the time of start-up.

Missed Surveillance

On December 23, 1987, the licensee notified the resident inspector that they had exceeded the time interval for a surveillance requirement (4.5.1.(d)) which requires the local verification of the isolation valves of the safety injection tanks to be open four hours prior to exceeding 1750 psi. The licensee stated that one hour after exceeding 1750 psi the

valves were verified open locally. The failure to meet the surveillance placed the licensee into Limiting Condition for Operation 3.0.3 which provides action to place the unit in Hot Standby within six hours. The unit had been in the Hot Standby condition since the plant trip due to misalignment of the permanent magnetic generator causing a loss of load.

After the plant trip and during the shutdown, the licensee determined that the duration of the repairs of the PMG would provide sufficient time to perform a cooldown. The unit commenced a cooldown, but before the plant reached Mode 4 (Hot Shutdown), the parts for the PMG became available and a decision was made to return to power operations.

The plant remained in Mode 3 throughout; however, pressure decreased below 1750 psi. A containment entry was not made while below 1750 psi and the ECCS systems remained operable. After recognition of the particular Technical Specification requirement, a containment entry was made principally to verify the open positions of the safety injection tanks isolation valves. This is a licensee identified violation (50-318/87-28-02).

The licensee's stated corrective action was to (1) reemphasize the literal and verbatim compliance with technical specifications and timely recognition of requirements not only before mode changes but also changes in plant parameter trends, and (2) to evaluate a possible change in technical specification requirements to add that verification be performed if any containment entry has been made while below 1750 psi or, in other words, to acknowledge that verification without reason is contrary to 10 CFR Part 20 ALARA concept and good operation practices.

No unacceptable conditions were noted.

6. Review of Licensee Event Reports (LERs)

LERs submitted to NRC:RI were reviewed to verify that the details 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 on-site follow up. The following LER's were reviewed:

LER No.	Event Date	Report Date	Subject
Unit 1			
87-12	07/23/87	12/03/87	Revision 1-Faulty 500KV Circuit Breaker Operation leads to Loss of Nonemergency AC Power
87-15	11/11/87	12/11/87	Reactor Trip Due to Transformer Short

LER No.	Event Date	Report Date	Subject
Unit 2			
87-08	11/22/87	12/22/87	Manual Trip as a Result of Two Dropped Control Element Assemblies

No unacceptable conditions were noted.

7. Radiological Controls

Radiological controls were observed on a routine basis during the reporting period. Standard industry radiological work practices, and conformance to radiological control procedures and 10 CFR Part 20 requirements were observed. Independent surveys of radiological boundaries and random surveys of non-radiological points throughout the facility were taken by the inspector.

No unacceptable conditions were identified.

8. Observation of Physical Security

Checks were made to determine whether security conditions met regulatory requirements, the physical security plan, and approved procedures. Those checks included security staffing, protected and vital area barriers, vehicle searches and personnel identification, access control, badging, and compensatory measures when required.

No unacceptable conditions were noted.

9. IE Bulletin Follow Up

The inspector reviewed licensee actions on the following IE Bulletin to determine that the written response was submitted within the required time period, that the response included the information requested including adequate corrective action commitments, and that licensee management had forwarded copies of the response to responsible on-site management. The review included discussions with licensee personnel and observations and review of the item discussed below.

NRC Compliance Bulletin 87-02, Fastener Testing

In accordance with NRC Bulletin 87-02, Fastener Testing to Determine Conformance with Applicable Material Specifications, and the applicable NRC Temporary Instruction for inspection (TI 2500/26), the inspector participated in the licensee's selection of fasteners to be tested. This bulletin remains open pending final review of the licensee's bulletin response and the results of their fastener testing.

10. Review of Periodic and Special Reports

Periodic and special reports submitted to the NRC pursuant to Technical Specification 6.9.1 and 6.9.2 were reviewed. The review ascertained: inclusion of information required by the NRC; test results and/or supporting information; consistency with design predictions and performance specifications; adequacy of planned corrective action for resolution of problems; determination whether any information should be classified as an abnormal occurrence, and validity of reported information. The following periodic reports were reviewed:

-- October and November 1987 Operations Status Reports for Calvert Cliffs No. 1 Unit and Calvert Cliffs No. 2 Unit, dated November 13 and December 14, 1987, respectively.

No unacceptable conditions were identified.

11. Unresolved Items

Unresolved items require more information to determine their acceptability. One item is discussed in Section 5.

12. Exit Interview

Meetings were periodically held with senior facility management to discuss the inspection scope and findings. A summary of findings was presented to the licensee at the end of the inspection.