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U. S. NUCLEAR REGULATORY COMMISSION
Region I

Docket/Report: 50-317/85-01 License: DPR-53
50-318/85-01 DPR-69

Licensee: Baltimore Gas and Electric Company

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

Inspection At: Lusby, Maryland

Dates: December 18, 1984 - January 22, 1985

Inspectors: TS Fenlin (FoR) 2/22/85
T. Foley, Senior Resident Inspector date

TS Fenlin (FoR) 2/22/85
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T. C. Elsasser, Chief, Reactor date
Projects Section 3C

Summary: December 18-January 22, 1985: Inspection Report 50-317/85-01, 50-318/85-01

Areas Inspected: Routine resident inspection (214 hours) of the control room, accessible parts of plant structures, plant operations, radiation protection, physical security, fire protection, plant operating records, maintenance, surveillance, open items, and reports to the NRC.

Results: The problems with Main Steam Isolation Valve operability identified in Report 317/318/84-31 appear to have been resolved (Paragraph 3.d). A review of the licensee's response to IE Bulletin 84-03, Refueling Cavity Water Seals, indicated that their analytical approach was generally sound; however, the NRC identified certain conditions which could affect analysis of cavity seal failure. The failure of the licensee to identify these conditions indicates a weakness in the depth of the safety committee's review of this issue (Paragraph 3). One violation was identified regarding failure to barricade or conspicuously post a High Radiation Area (Paragraph 3.c).

DETAILS

1. Persons Contacted

   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.

2. Summary of Facility Activities

   Details of the following are included in the body of this report.

   Unit 2 operated at full power throughout the reporting period with only periodic load reductions. At the beginning of this period Unit 1 was in Cold Shutdown to repair #11 and #12 Main Steam Isolation Valves (MSIV's). The unit had been shutdown on December 12, 1984 due to a hydraulic fluid leak which had developed on the rod end of the #11 MSIV actuator. That leak had raised concerns regarding the adequacy of hydraulic dampening during valve closure. During the shutdown #12 MSIV failed to fully close on demand. While Unit 1 was shutdown, seal packages on two reactor coolant pumps #11B and #12A were replaced.

   Unit 1 resumed power operation on December 26. The #11 MSIV had been repaired. The root cause of the #12 MSIV failure had not been positively identified but the valve was successfully tested thirteen times. Subsequent troubleshooting efforts during power operation showed that the MSIV 12 failure was related to insufficient hydraulic fluid inventory. Subsequent corrective action increased accumulator fluid inventory on all MSIV's which should correct the recurring MSIV failure problem.

   On January 16, 1985, Unit 1 was shutdown to Mode 4 (Hot Shutdown) to correct Safety Injection Tank (SIT) check valve back leakage problems on #11A and #11B SIT's. The leakage was observed when the High Pressure Safety Injection System (HPSI) was placed in operation and could, under certain accident conditions, have resulted in insufficient HPSI flow to the Reactor Coolant System. In accordance with their Emergency Plan the licensee declared an Unusual Event due to a Technical Specification required shutdown. During the outage #11 and #12 MSIV were tested and demonstrated operable. Power operation on Unit 1 was resumed on January 19, 1985.

3. Licensee Action on Previous Inspection Findings

   (Open) Inspector Follow Item (317/84-31-02) Refueling Cavity Water Seal, IEB 84-03. The inspector reviewed the licensee's responses, dated December 4 and 11, 1984, to the subject bulletin. Additional background information was obtained from licensee personnel involved in response development.

The refueling pool seal consists of a single steel ring placed in the opening between the reactor vessel flange and the refueling pool floor. It rests on six support brackets equally spaced around the vessel. A one-inch annular gap exists between the inside of the ring and the reactor vessel and between the outside of the ring and the seal ring ledge of the refueling pool. The gaps are sealed by two M-shaped silicone rubber seals, each one enveloped by nine steel channel covers placed end-to-end around the seal circumference. The covers are held down by 45 clamps spaced equally around the outer seal and 36 clamps similarly arranged around the inner seal.

For analysis purposes the licensee postulated a failure of one clamp and, as a result, complete failure of the seal between the affected clamp and the adjacent clamps. The worst case would be for such a failure to occur on the outer annular seal (0.27 square foot leak area). In their response the licensee stated that loads large enough to accomplish such damage are, in general, not permitted over the refueling pool. They acknowledged that the upper guide structure is sufficiently large to cause such damage, but that structure is not normally moved while the transfer tube, connecting the refueling cavity to the spent fuel pool is open, and must be moved prior to any fuel movement. The inspector asked if the damage that could result from the dropping of a fuel assembly (during fuel movement the bottom of a fuel assembly would pass over the seals with about 1.38 feet vertical clearance) had been analyzed. The licensee had not specifically analyzed the consequences of a fuel assembly (FA) drop. On a qualitative basis, however, they felt that their postulated failure was conservative and would bound a FA drop. Although the licensee's approach appeared conservative, NRC I&E Headquarters Guidance to inspectors (Temporary Instruction 2515/66) stated that the impact of a FA drop on the seal should be considered in the failure mode analysis. Therefore, the inspector asked the licensee to confirm that their postulated failure would be bounding for a FA drop event. By calculation, the licensee then confirmed their assumed failure was bounding.

The licensee had considered two accident scenarios, seal failure with the fuel transfer tube open and failure with the tube isolated (valve shut). In both scenarios, a FA was assumed to be in the fully raised position in the refueling machine. Normal water level is 8-1/2 feet above the top of a FA in the raised position. In both scenarios, no credit was taken for makeup, and no credit was taken for operator action after radiation levels reached 1 rem/hr. For the tube open scenario, total time for operator action to both detect the seal failure and complete action to lower the FA into the reactor vessel or deep end of the pool would be about 29 minutes. For the tube closed scenario, total time for detection and completion of operator action would be about 16-18 minutes. The licensee stated that it is possible to detect the failure and move the assembly to a safe position in this time frame. Inspector guidance indicated no operator action should be credited for the first 10 minutes after failure detection. Cavity level would drop at an initial rate of about 0.3 feet/minute to 0.5 feet/minute. Unless the operators spot a dropping water level, warning of a problem could come from an area radiation monitor on the refueling bridge (30 mr/hr) or from a Containment sump level increase alarm at 49 gallons. It would take about a 1-2 foot level drop to cause the area monitor to alarm but less than a one foot drop for a sufficient amount of water to leak to actuate the sump alarm. The licensee estimates that the operators, once alerted, could reposition a FA from the worst initial position to a safe position in 3 to 5 minutes. Provided the operators detect the decreasing water level within 3 minutes of leak initiation (this means principle reliance on the sump alarm), the licensee marginally meets the above 10 minute criteria.

The fuel carriage must be on the spent fuel pool (SFP) side for the transfer tube isolation valve to be shut. Adequate time exists to shut the fuel transfer valve (121 minutes available). In a worst case situation, with the transfer valve remaining open (due to a immovable carriage or some other reason), the lowest drain down level of the SFP would be at about the top of the FA's. In unusual situations, a FA may be seated in a raised position in the fuel rack for reconstitution procedures. In that case, the lowest water level would be below the top of the elevated FA(s). The inspectors asked if the possibility of uncovering the fuel during reconstitution had been considered. The licensee had not recognized that this could happen.

The inspector reviewed licensee operating procedures to see if they adequately addressed cavity seal failure events. The applicable action listed in Abnormal Operation Procedure AOP 6D, Revision 7, "Fuel Handling Incident" is somewhat vague in that it states only to "Insure the safety of any fuel being handled and evacuate the Containment". More details on what actions are necessary to ensure fuel safety are needed. The Alarm Manual did properly state that the FA should be lowered when area radiation alarms are received on the refueling machine and the SFP service platform (monitors I-RI-7009 and O-RI-7025). That same manual, however, did not provide actions for cavity seal leakage situations when SFP level, Containment area radiation, and SFP area radiation alarms are received. Procedures are available for providing makeup water to the SFP from the Refueling Water Tank which could be used in the event of a serious cavity seal failure (Operation Instruction OI 24, Revision 17, "SFP Cooling"). In the event of a cavity seal failure with the transfer tube closed, no procedure is available for providing makeup water to the deep end of the refueling cavity for cooling of a FA placed in that area. Production Maintenance Department Instruction RV-9 does properly address seal inspection, installation, and pressure test procedures. Procedural deficiencies noted above were pointed out to the licensee.

Inspector guidance material indicated that the seal assembly should have been initially hydrostatically tested to at least two times the maximum head of water on the seal for credit to be given for seal integrity. The licensee stated that such a test had not been performed.

A final area of inspector concern is that the cavity seal is not seismically designed. When the inspector raised this concern, the licensee performed an analysis of the effect of a seismic event on seal integrity. That analysis indicates that the seal could withstand a seismic event without significant damage.

This cavity seal bulletin item remains open pending resolution of the apparent deficiencies described above.

a. Daily Inspection

During routine facility and daily Control Room 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, radiation monitoring, emergency power source operability, control room logs, shift supervisor logs, tagout logs, and operating orders.

No violations were identified.

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 was checked. Visual inspections of major components were performed. Operability of instruments essential to system performance was assessed. The following systems were checked:

-- No. 11 Diesel Generator checked on January 16, 1985.
-- Unit 2 Salt Water System checked on January 8, 1985.

No violations were identified.

c. Biweekly and Other Inspections

During plant tours, the inspector 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.

Radiation Area Postings

-- On January 14, 1985, the inspector made a routine tour of the Unit 1 controlled area and noted a platform located in the 5 foot West Penetration Room which was accessible by a ladder through erected staging. The staging was elevated to just below the 27 foot West Penetration Room which is generally a "locked High Radiation Area". The inspector utilized the local Health Physics technician's survey instrument and measured 200 mr/hr at 18 inches from an insulated safety injection system pipe at eye level while standing on the platform. Neither this area, the ladder or the platform were posted with radiation or high radiation signs nor was the area barricaded; however, the entrance to the controlled area is posted "Radiation Area" and the entrance to the West Penetration Room is equipped with a door. Technical Specification 6.12.1. a requires that high radiation areas be posted and barricaded and entrance thereto controlled by issuance of a radiation work permit. Contrary to the above, this area/platform provided access to the area in the overhead of the 5 foot West Penetration Room, where a High Radiation Area existed, but was not posted or barricaded. This is a violation (50-317/85-01-01).

Further discussions with Health Physics technicians indicated that the staging had been set up for several months and the specific work being performed had since been forgotten. However, radiation work permits are required for all access to the controlled area and a "check in" with the "Rad Con" supervisor is required prior to performing any work in the controlled area.

A search of past surveys did not reveal any surveys of the area in question. Health Physics technicians properly posted the area upon notification by the inspector.

-- During this period the licensee received IE Information Notice No. 84-82, "Guidance for Posting Radiation Areas". The inspector toured the controlled area to determine whether the licensee was incorporating the guidance provided. A determination was made that radiation signs are posted primarily at the entrances to rooms and the entrance to the controlled area "Auxiliary Building" and not at each location within the Auxiliary Building thereby "desensitizing" and failing to "properly" alert personnel of the presence and "specific" location of radiation areas.

This was discussed with the Assistant General Supervisor (AGS) of Radiation Protection and a mutual agreement was reached that (1) most of the Auxiliary Building was technically not a radiation area; however, due to handling and processing of radioactive material, may become a radiation area; (2) there exist approximately ten locations within the Auxiliary Building where radiation levels significantly increased from 1 mr/hr to 10-25 mr/hr without any postings to make personnel aware of the change in radiation levels; and (3) the AGS agreed to post these areas with signs, alerting personnel to the specific locations of these higher than normal radiation areas. This will be followed by the NRC (IFI 317/85-01-02).

d. Other Checks

Control Room Ventilation

-- On January 3, 1985, during the performance of a Control Room emergency ventilation system surveillance test procedure (STP 0-97) the compressor for #12 air conditioning unit appeared to be cycling excessively. The licensee initially believed the problem was being caused by too much air flow over the refrigerant condenser tubes.

After performance of an engineering analysis, one condenser fan was disabled. Further investigation showed that the root cause was actually a misadjusted "Hot-Bypass Valve". The valve was adjusted and the original condenser fan configuration restored.

Main Steam Isolation Valves

-- Inspection Report 317/318-84-31 detailed the failure, repair, testing, subsequent declaration of the Main Steam Isolation Valves (MSIVs) operability, and the inspectors' reservations regarding the valves reliability. The inspectors questioned the reliability of the valves operability even though the licensee performed thirteen successful sequential tests of the valve. The inspectors calculated hydraulic fluid volumes, design pressures, and obtained empirical data of the system and compared it to the vendor's Technical Manual. The results of this comparison indicated that the Main Steam Isolation Valve Hydraulic System did not display pressures which closely correlate to the vendor's manual. Subsequently testing of the previously removed failed component from the No. 12 MSIV revealed that the components worked properly, and the root cause had not been identified.

On January 10, 1985, the inspectors discussed the lack of identification of a root cause and apparent inconsistencies regarding empirical data versus design data with the site manager. The licensee shared the inspectors concern regarding the reliability of the MSIV and committed to commence a 24 hour a day test program, conduct an engineering evaluation and seek vendor recommendations to solve the problem.

Subsequently, on January 14, 1985 the licensee identified that the charging procedure for filling the accumulator bladders with nitrogen was inadequate. The procedure requires a nitrogen charge of 2900 +/- 100 pounds in the bladder within the accumulator then a hydraulic fluid charge to 5000 pounds. This should supply approximately 3.5 gallons of hydraulic fluid from each of the (18) accumulators or approximately 63 gallons to stroke the valve. The charging procedure, however, also required charging 3000 pounds of nitrogen (which became cold due to the adiabatic expansion of gas into the accumulator and subsequently heated up to room temperature). The unaccounted for temperature rise increased the bladder pressure to approximately 3150 psi. This resulted in the delivery of only approximately 2.4 gallons from each accumulator or a total of about 43.9 gallons. The vendor states that a volume of 41.9 gallons is required to successfully stroke one valve. Each valve has a separate hydraulic package to provide this volume. The licensee revised their procedure for filling accumulator bladders to ensure a pre-charge pressure of 2900 pounds with sufficient time to ensure the pressure is stable at 2900 pounds before charging the accumulators to 5000 pounds with hydraulic fluid. This was performed on all hydraulic packages for both units. The licensee demonstrated by bleeding down each accumulator the available fluid and determined that 3 gallons was being delivered from each accumulator or approximately 54 gallons for each valve.

This provided the licensee additional confidence that the MSIVs were more reliable. The inspectors believed that a dynamic test of the MSIVs should be performed to verify the static tests conclusions. The licensee contended that they had produced sufficient data by draining each accumulator and by calculating volumes that a dynamic test was not warranted. Additionally, the licensee added more volume to the system which was previously demonstrated operable by thirteen consecutive successful tests. The inspectors maintained that good engineering practices would have a dynamic test performed that demonstrates the stated conclusions. This was discussed with Region I management. The licensee expressed a desire to make a presentation to the NRC management expressing their views, prior to making a final decision whether or not to shut the unit down and test the MSIVs. This meeting was scheduled for January 25, 1985.

However, prior to the meeting another problem developed on January 16 relating to Safety Injection check valves which required a unit shutdown. The MSIVs were subsequently cycled three times hot and three times cold. All parameters appeared to more closely approximate those discussed in the vendor's manual. The inspectors witnessed the above test and had no further questions about the valves reliability at that time.

On January 17, 1985, the licensee stroked the #12 MSIV successfully with four accumulators isolated. With five accumulators isolated, the valve hydraulically locked up displaying parameters similar to those of the previous test failures. This test confirmed the suspicion that the deliverable oil volume was insufficient during the failed tests. The intermittent lack of deliverable oil was due to the slight variability of deliverable oil with each stroke and primarily for failure to allow for adiabatic expansion of the nitrogen gas when added to accumulators. Correction of the identified deficiency yielded an approximate 20% to 28% excess hydraulic fluid available following the valve stroke which resolved the question of long term operability of the valve.

The inspector found that the licensee identified the procedural inadequacy; that they reported this to the NRC residents; that it could not have reasonably been expected to be prevented from a previous violation's corrective action; and that the licensee took corrective action which should prevent recurrence. This matter is considered a licensee identified violation that meets the NRC enforcement policy for not issuing a notice of violation. Notwithstanding, the inspectors note that the licensee's performance regarding timeliness relating to the corrective action and identification of the root cause was delayed, and required NRC urging to expedite the action.

No violations were identified.

5. Events Requiring Prompt Notification

The circumstances surrounding the following events requiring prompt NRC notification pursuant to 10CFR50.72 were reviewed. For those events resulting in a plant trip, the inspectors reviewed plant parameters, chart recorders, logs, computer printouts and discussed the event with cognizant licensee personnel to ascertain that the cause of the event had been thoroughly investigated; identified, reviewed, corrected and reported as required.

-- At 4:42 p.m. on January 16, the licensee initiated a controlled shutdown of Unit 1 after discovering in leakage into #11A and 11B Safety Injection Tanks (SIT) when the High Pressure Safety Injection (HPSI) system was operating. The leakage path was identified to be a total of 38 gpm reverse flow through the SIT discharge check valves. There was no evidence of leakage through the Reactor Coolant System (RCS) check valves. In accordance with their emergency plan the licensee declared an Unusual Event due to a Technical Specification required shutdown. The HPSI system was declared inoperable due to potential insufficient flow rate (during accident conditions) to the RCS as a result of the above identified leakage to the SIT's. The licensee proceeded to Mode 4 (Hot Shutdown) to repair the valve. Appropriate notifications for the unusual event were made. The licensee replaced O-rings in each valve and returned to power operation on January 27, 1985. In this case the licensee promptly identified the deficiencies, demonstrated a clear understanding of the issue and exhibited prompt and effective corrective action.

No violations were identified.

6. Observations 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 violations were identified.

7. Review of Licensee Event Reports (LER's)

a. LER's 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 onsite followup. The following LER's were reviewed.

LER No.	Event Date	Report Date	Subject
Unit 1			
84-16	12/15/84	01/14/85	HPSI Injection Leg's Flow Imbalanced
84-18	12/12/84	01/09/85	No. 11 MSIV Inoperable Due to Excessive Actuator Piston Rod Rod Seal Leakage
84-19	12/12/84	01/09/85	Failure of No. 12 MSIV to Fully Close During Surveillance Testing

b. For the LER's selected for onsite review, the inspector verified that appropriate corrective action was taken or responsibility assigned and that continued operation of the facility was conducted in accordance with Technical Specifications and did not constitute an unreviewed safety question as defined in 10 CFR 50.59. Report accuracy, compliance with current reporting requirements and applicability to other site systems and components were also reviewed.

-- LER 317/84-16 was discussed in Inspection Report 317/318-84-31.

-- LER's 317/84-18 and 19 were thoroughly investigated by the inspectors and the details are documented herein and in Inspection Report 317/318-84-31.

8. 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.

-- P84-7828, Elbow Replacement No. 12 Salt Water Header observed on December 31, 1984.

No violations were identified.

9. Surveillance Testing

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. The following tests were reviewed:

-- M-200-2, Reactor Trip Breaker (RTB) Functional Checks.

-- 0-1-1, Main Steam Isolation Valve Test.
-- M-471-1, Air Lock Operability and Leak Rate Test.
-- M-571-2, Local Leak Rate Test.
-- M-672-B-2, Pressure Relief Valve (ERV) Channel Functional Test.
-- M-171-2, Personnel Lock Gasket Seal Test.

-- The RTB functional check has been changed to include the licensee commitments of increasing (doubling) the testing frequency of those RTBs than do not meet the new acceptance criteria. The new functional check lowers the acceptable RTB opening time to 100 milliseconds. The inspectors verified the functional checks were conducted in accordance with the revised criteria.

-- On January 10, 1985, the inspector witnessed the Unit 1 Emergency Personnel Air Lock Door operability and Leak Rate Test (STP-M-471-1). The inspector determined through observation and review of the procedure the following:

  -- Test pressure was inadequately specified to be "at least 50 psi" without regard for exceeding design pressures. No tolerance or maximum pressure was specified.

  -- No relief protection was installed on the test apparatus or on the personnel air lock, nor was any required to be installed.

  -- The air supply providing air to the personnel air lock was isolated by a single valve which could leak and provide invalid test results. The source should be positively isolated (i.e., disconnected).

  -- Connection of leak rate monitoring equipment is not specific.

  -- No assurances are provided that a strong back is installed on the inner Containment door.

The inspector discussed these inadequacies with the Test Coordinator then reviewed several other test to identify similar concerns. The review revealed no similar concerns, however, the review was limited in scope. The inspector determined that this matter is unresolved pending further review to identify whether this is an isolated case or a more general problem (317/85-01-03; 318/85-01-01).

10. <u>Radiological Controls</u>

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

Other than the condition discussed in Paragraph 3.c., no problems were identified.

11. 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:

-- December 1984 Operation Status Reports for Calvert Cliffs No. 1 Unit and Calvert Cliffs No. 2 Unit, dated January 14, 1985.

No deficiencies were noted.

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.