

U. S. NUCLEAR REGULATORY COMMISSION
Region I

Docket/Report: 50-317/85-02
50-318/85-02

License: DPR-53
DPR-69

Licensee: Baltimore Gas and Electric Company

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

Inspection At: Lusby, Maryland

Dates: January 22, 1985 - February 19, 1985

Inspectors:

T. C. Elsass
T. C. Elsass, Senior Resident Inspector

3/15/85
date

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Approved:

T. C. Elsass
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Projects Section 3C

3/15/85
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Summary: January 22 - February 19, 1985: Report No. 50-317/85-02, 50-318/85-02.

Areas Inspected: Monthly resident inspection (238 hours) of the control room, accessible parts of plant structures, plant operations, radiation protection, physical security, maintenance, surveillance, IE Bulletins, open items, reports to the NRC, and corrective actions in response to Inspection Report 50-317/318-84-31.

Results: No violations were identified. Significant issues evaluated included: reactor trip caused by a personnel error (Section 6), lack of thoroughness in the design process when modifying the Engineered Safety Feature Actuation System (Section 13), actions to correct Reactor Trip Breaker material problems and improved surveillance testing procedures (Section 10), and improvements in housekeeping practices (Section 3).

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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. Correction to Inspection Report 50-317/318-84-31

NRC Inspection Report 84-31 for Calvert Cliffs Nuclear Power Plant issued February 6, 1985 was released containing an error on page 9, paragraph 5 "Independent Inspection". In the last sentence (Sample Point Number 5) the word "released" was inadvertently omitted. To further clarify the statement, the sentence should read "(5) Drainage/runoff from the onsite "landfill" where surveyed and released controlled material is periodically buried in an effort to reduce (the amount of) radiological waste (shipped)."

3. Summary of Facility Activities

Unit 2 continued operation throughout this period (140 days since last shut-down). Both units entered the period operating at full power. Both experienced Reactor Coolant System (RCS) unidentified leakage of 1+/- .2 gpm periodically during the period. Each time this occurred the leakage was identified and isolated or sealed. On February 5, Unit 1 automatically tripped due to low steam generator water level caused by a loss of #11 instrument AC bus due to operator error. On February 7, during surveillance testing of control rods, Group A control rods failed to respond. A plant shut down was initiated, however a ground was identified on the control rod logic module and corrected before the shut down was completed. The unit immediately returned to power and both units operated continuously through the end of the period.

In general, most areas of the plant have improved in housekeeping, especially those areas that were of below average appearance (i.e., intake structure and service water pump rooms). The licensee is now sand blasting the rust coated piping associated with a few parts of the salt water system and will then epoxy coat them. Additional painting is occurring in various parts of the facility improving overall appearance. Preparations are in progress for the Unit 1 refueling, scheduled to occur on April 6, 1985.

On February 1, a reorganization of specific licensee personnel took place as a career development opportunity. These changes affect the General Supervisor Operations (GSO), General Supervisor, Quality Assurance (GSQA), General Supervisor, Planning and Support, and the following principal engineer positions: Technical Support; Plant Engineering, Nuclear; Operational Licensing and Safety; Construction Engineering Modifications Engineering Unit; and Production Maintenance.

The inspectors ascertained that the personnel qualifications of personnel in management positions required by ANSI N-18.1 Selection and Training of Nuclear Power Plant Personnel-1978, were met or exceeded. No inadequacies were identified.

4. Licensee Action on Previous Inspection Findings

(Closed) Inspector Follow Item (317/84-31-03). Licensee to Evaluate Lower than Expected Lift Off Force for Unit 1 Containment Hoop Tendon 42H52. An engineering evaluation was performed which showed that the Containment prestressing system will meet minimum design requirements throughout the life of the plant. A worst case extrapolation of lift off force for tendon 42H52 showed, at end of plant life (40 years), that it would exceed the minimum design value (536 kips). This item is closed.

(Closed) Inspector Follow Item (317/82-16-02). Need to Establish Procedural Controls to Assure Proper Throttling of Pressurizer Spray Bypass Valves. Operating Procedure OP-1, Revision 25, Step 34, now requires a verification of proper bypass valve throttling by checking temperatures downstream of the spray valves with the spray valves shut and Reactor Coolant Temperature at 500-505 degrees Fahrenheit. If temperatures are not within this band, the operator is referred to an Operating Instruction (currently designated OI-1H dated April 11, 1984) which specifies how the bypass valve throttle positions are to be established and recorded. This item is closed.

(Closed) Inspection Follow Item (317/81-13-02). Slow Closure Time of #12 Main Steam Isolation Valve (MSIV). This item was updated in Section 2 of Inspection Report 50-317/84-03, 50-318/84-03. As described in that report the cause of the problem was identified to be galling of the valve stem due to use of an improper type of steel in the valve's junk ring. Closure of this item was delayed pending confirmation that the problem has not recurred. The licensee informed the inspector that the problem has not recurred. The junk rings on all MSIV's have now been replaced with the proper material and only rings of the correct material are maintained in stores. During the period of December 1984 - January 1985, an unrelated problem was identified on #12 MSIV where, due to an insufficiency in hydraulic fluid inventory, hydraulic locks periodically prevented valve closure. This problem was corrected (Inspection Report 50-317/85-01, 50-318/85-01). During the troubleshooting and resolution of the hydraulic lock problem, #12 MSIV was successfully tested 17 times without recurrence of the slow closure time problem. This item is closed.

(Closed) Inspector Follow Item (317/84-19-03). STP-0-72-0 "Control Room Ventilation" Was Found Inadequate. An audit by the licensee of all other surveillance procedures was in progress and not previously available for review. The inspector reviewed the five part audit which identified fourteen findings. Because of the significant number of findings, this concern was brought to the attention of the Plant Superintendent for a bi-annual review. The inspector's review of five audits determined that the scope of the audit did determine that the specific Technical Specification was addressed by a surveillance procedure, however the audit did not determine that the surveillance procedure adequately met the intent of the Technical Specification. Discussion with the Quality Assurance Supervisor indicated that another audit was in progress to determine the adequacy of each surveillance procedure. This item is closed.

5. Review of Plant Operations

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, radiation monitoring, emergency power source operability, control room logs, shift supervisor logs, tagout logs, and operating orders.

Annunciators

During daily tours of the Control Room, inspectors have observed specific annunciators that are continuously in the alarm (energized) condition. The conditions causing the alarm are identified as "in for no apparent reason" or the alarm condition is known and justified because of a particular plant condition or line up, or the annunciator is malfunctioning and has a Maintenance Request (MR) identifying the discrepancy. There are approximately four annunciators on Unit 2 and one on Unit 1 control boards that are in this category. The licensee maintains control of out of service (OOS) annunciators via a Calvert Cliffs Instruction (CCI-306) "Alarm Annunciator Control". A review of CCI-306 revealed approximately twenty OOS annunciators total for both units. Each of twenty alarms OOS had a justification/evaluation and were reviewed by the Shift Supervisor. The continually energized annunciators above were not among those recorded in the CCI evaluation.

The inspector discussed the importance of maintaining a "Blackboard" concept with the General Supervisor of Operations (GSO). The GSO agreed that when the annunciators were continuously energized they were no longer fulfilling their intended function of alerting the operator of changing conditions, and an additional effort would be placed on minimizing the number of energized annunciators.

When questioned by the inspector each operator was fully knowledgeable of the reasons for each lit annunciator; however, operators admitted that some currently lit annunciators would no longer alert them to changing conditions in the applicable areas. This will be followed by the inspector during daily tours of the Control Room (IFI 85-02-03).

RCS Leakage

Following an increase in the calculated Reactor Coolant System (RCS) leak rate, the licensee reduced power on Unit 2 on January 30, 1985 to permit personnel access into Containment Reactor Coolant Pump (RCP) Bays for leak source identification. A leak was found on a capped lower RCP seal pressure sensing line. Net RCS unidentified leakage then reduced to 0.798 gpm (within the Technical Specification limit of 1 gpm) and the unit returned to full power operation. On January 31, 1985 calculated

RCS unidentified leakage was calculated to be 1.342 gpm. The source of leakage was determined to be a pressurizer sample line isolation valve. Sealant material was injected into the valve and the leakage was stopped. On February 1, RCS unit leakage was calculated to be 0.951. A packing leak on the pressurizer pressure transmitter isolation valve (RC 267 for PT 102A) was located and the leak sealed.

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:

- Unit 1 Auxiliary Feedwater System checked on January 30, 1985.
- Unit 1 Instrument and Plant Air checked on February 7, 1985.
- Unit 1 Salt Water System in Service Water Room checked on February 13, 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. Verification of the following tagouts indicated that the tagout procedures were properly conducted.

- Tagout 5632, Unit 1 Safety Injection Tank MOV's checked on January 30, 1985.
- Tagout 9181, Unit 1 Instrument Air Compressor #11 checked on February 7, 1985.
- Tagout 9089, #21 Diesel Generator checked on February 15, 1985.

Electrical Panel Inspection

An independent inspection was made by the inspector of accessible and normally inaccessible cable trays, chases, electrical panels, breakers and electrical penetration and switchgear rooms.

In general, all areas were very clean. Cables were in a neat array and properly bundled or harnessed. Cable trays observed were all less than half full, with no debris and little dust. Breaker cabinets and electrical rooms were also maintained. Some cable chases, however, where construction was ongoing, had minor debris about the bottom of the chase.

Tour of the back of the Control Room panels, specifically panels 1C09 and 2C09 revealed excessive improperly terminated wires, wires not harnessed nor properly bundled. Lifted leads with lugs attached without protection (i.e., tape) and numerous bare/exposed wires also existed reflecting poor quality and workmanship standards.

Discussions with Instrument and Control personnel revealed that this area was undergoing modifications for the new plant computer. This, however, is only responsible for a small portion of the concern. The majority is as a result of previous modifications which removed components but the wires were not properly terminated. The licensee further stated a program is currently under review to upgrade the Control Room electrical panels by providing improved labeling of: terminal blocks, spare leads, lifted wires and properly terminating non-functional wires. This condition was only observed behind panels 1C09 and 2C09. Aside from this area, electrical standards appear to be met in all areas observed. Periodic tours will be conducted by the inspector to monitor the licensee's progress in completing the work associated with the installation of the plant computer and improving the electrical workmanship in this area. This matter was also discussed with the Plant Superintendent, who also related that the program which upgrades the Control Room panels should alleviate this concern. The inspector had no further questions but will follow the licensee's corrective action (IFI 85-02-04).

No violations were identified.

d. Other Checks

Solenoid Valve Vent Path Plugged

During a routine surveillance test on January 11, 1984, the licensee identified an inoperable Salt Water Valve (2-SW-5163) on the discharge of a Component Cooling Heat Exchanger. A cap was found over the vent port on the solenoid valve which operates the valve. Obstruction of this vent path prevented valve opening. An investigation of maintenance activities affecting the valve since the previous successful surveillance test (December 5, 1984) provided no indication of how or why the cap was installed. Typically when this type of valve is disabled for maintenance, vent caps are not used. To prevent similar occurrences in the future, the licensee will install a "gooseneck" copper tube on all vents from safety related control valves. (Vents without goosenecks are threaded which can suggest that a cap or fitting is missing.) Procedural controls are in place to prevent uncontrolled installation of such devices (Calvert Cliffs Instruction CCI 117 D, "Temporary Mechanical Device, Elec-

trical Jumper, and Lifted Wire Controls"). Obstruction of solenoid vents has not been noted previously, and this appears to be an isolated event. The inspector checked the vents on other salt water system valves in the area. No other vent obstructions were noted. This is a licensee identified violation meeting the criteria of 10CFR2, Appendix C, Paragraph 5.A. Therefore, a notice of violation will not be issued.

6. Events Requiring Prompt Notification

The circumstances surrounding the following events requiring prompt NRC notification pursuant to 10 CFR 50.72 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.

Reactor Trip

At 4:58 p.m. on February 5, 1985, the Unit 1 Reactor tripped on low steam generator level following the loss of both Main Feedwater (MFW) pumps. The Auxiliary Feedwater system started as designed and supplied water to the steam generators. The plant was quickly stabilized following the trip. The MFW pump trips resulted from an operator error. The operator was supposed to open the control power breaker to the #11 Instrument Air Compressor (which was out of service for maintenance) to clear a hanging annunciator. Instead he opened a breaker to Instrument AC Transformer #11. This caused (1) a loss of power to the differential pressure (D/P) transmitters for the MFW regulating valves resulting in a falsely high D/P output being sensed by the MFW pumps, (2) the MFW pumps to reduce speed in response to the high D/P signal, (3) and an increase in condenser hotwell level due to the failing open of condensate pump and booster pump recirculation valves and the makeup valve. When the improper breaker opening was recognized, the breaker was reclosed. D/P transmitter outputs reduced causing the MFW pumps to increase speed. Concurrently, the above recirculation valves and makeup valve shut and the condenser dump valve opened. The MFW pump speed increase in combination with a decreasing hotwell level led to trips of both MFW pumps on low suction pressure. The event initiated because the operator involved did not recognize that he was to open a small breaker (#9) on the P-panel of Motor Control Center MCC 114. Instead he initially erroneously located a 480 volt breaker #9 (full designation is 52-11409) on MCC 114. Seeing that this breaker had no association with the instrument air compressor, he assumed that Control Room personnel had told him the wrong breaker number. He then located a breaker labelled "Instrument A.C. Transf.11" (52-11429) and believed it powered Instrument Air Compressor #11. He mistakenly then opened that breaker and initiated the event.

Overall, labeling of plant components is very good. The licensee is evaluating further improvements in labeling as a result of this event. The licensee determined that sufficient training had been given to the individual which should have prevented this type of error. Nevertheless, the licensee is examining possible improvements in operator training in the electrical area.

The operator appeared to have acted on impulse without sufficient thought. As stated in the most recent SALP report 50-317/84-29, 50-318/84-29 the licensee tracks personnel errors throughout the plant and a general decrease in the number of personnel errors has been observed.

No violations were identified.

7. 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.

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

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 was reviewed.

<u>LER No.</u>	<u>Event Date</u>	<u>Report Date</u>	<u>Subject</u>
<u>Unit 1</u>			
85-01	01/16/85	02/08/85	Safety Injection Tank Check Valve Inleakage Test

No violations were identified.

9. 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 reviewed.

-- Coupling Alignment on #12 Salt Water Pump observed on February 1, 1985.

On January 26, 1985, the failure of two of six bolts securing a diffuser plate in the air inlet to #12 Diesel Generator was noted by licensee personnel. The bolts were approximately 1/2 inch in diameter (Grade 5). The diffuser

plate is located at a point in the air inlet header immediately ahead of the turbochargers. Maintenance personnel could recall similar failures previously on #12 diesel and #11 diesel. Following the earlier failures, bolting material was upgraded from Grade 2 to Grade 5.

In conversation with the diesel vendor, the licensee learned that because of operational problems, later model diesels now have a different diffuser plate arrangement. The broken bolts were recovered and replaced, and the licensee is evaluating final corrective action options. Furthermore, the licensee is informing other utilities, who may have the same model diesels. Final corrective action will be followed by the NRC (IFI 317/85-02-01). The diesel was manufactured by Colt-Fairbanks Morse, Model #4816, 12 cylinder, opposed piston type.

No violations were identified.

10. 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:

- STP-0-7-1, ESF Logic and Performance Test (January 24, 1985).
- STP-M-210-1, RPS Functional Test (January 25, 1985).
- Reactor Trip Breaker Testing on Unit 1 and 2 (February 5, 1985).

On February 2, 1985, the inspectors witnessed the licensee conduct "in cubicle" time response testing of the scram breaker's undervoltage trip coil's for Unit 1. The Reactor Trip Breakers (RTBs) are GE type AK-2-25. Previous testing of the RTBs has been "out of cubicle" testing, requiring that the breaker be cycled once prior to the actual time response test. The NRC maintained that this test condition does not demonstrate the "as found" condition of the breaker and would not accurately reproduce the initial response time. Previously, the licensee maintained that in-place testing of the RTBs was not necessary to demonstrate proper functioning within the required time frame and such testing would impose significant personnel safety hazard when connecting the test gear. As a result of placing additional emphasis on this matter, the licensee determined a method of testing the breakers in place without imposing a significant personnel hazard during the test set up. On February 5, 1985, the results of this testing indicated that three breakers exceeded the 100 msec acceptance criteria as follows; Unit 2, TCB-6, 216 msec; TCB-1, 610 msec; and TCB-5, 116 msec. All the other breakers on both units were less than 50 msec. Fifty (50) msec or less is normal for these breakers, as evidenced by two years of trending RTB time responses. Subsequently, the slow breakers were immediately retested without any maintenance, except the previous cycle due to this test. The results were TCB-1, 68 msec; TCB-5, 56 msec; TCB-6, 132 msec. The licensee then performed corrective

maintenance on these breakers. All breakers whose response times were slow were of the old Front Frame Assembly style. The licensee then retested the breakers satisfactorily. As a result of these failures, the licensee committed to: (1) rearrange the RTB's such that a new Front Frame Assembly is located in each Reactor trip path, to ensure a Reactor trip would occur within the analyzed time frame; (2) conduct future tests of the RTB's "in place" to ensure accurate "as found" response time results; (3) continue to pursue obtaining new Front Frame Assemblies for all breakers; and (4) continue to pursue a modification to facilitate in place testing of the RTBs.

During the previously mentioned corrective action on the breakers, the licensee noted that on TCB-1 the undervoltage (UV) coil laminations were separating and believed that this separation caused the excessive time delay response of TCB-1. Troubleshooting identified the cause to be a manufacturing defect in the portion of the armature immediately above the coil which is made up of laminated sections rivetted together. The laminations were loose such that relative vertical movement between sections was possible. Under the influence of the magnetic flux created by the coil when energized, several laminations were pulled to a lower vertical position than the remaining sections which actually contacted the shading ring of the coil. By design, there should be no lamination/shading ring contact. The licensee believes that when physical contact exists and the coil is deenergized, response time is delayed due to the hysteresis (or amplified hysteresis) effect. The licensee replaced this coil with a new UV coil. A Facility Change Request (FCR) has been initiated to upgrade the UV coil to an improved larger and more durable device. The inspector documented and forwarded this matter to Region I as a potentially generic issue. This has been a long standing regulatory issue with the NRC, first identified in Inspection Report 50-317/83-18, 50-318/83-18. Although the resolution of this issue appears to now be acceptable, considerable NRC effort was needed. The inspectors regularly observe testing of the RTB's during routine tours of the plant and will continue to monitor the progress of the above modifications and testing (IFI 85-02-05).

No violations were identified.

11. IE Bulletin Followup

The inspector reviewed licensee actions on the following IE Bulletins to determine that the written responses were submitted within the required time period, that the responses included the information requested including adequate corrective action commitments, and that the licensee management had forwarded copies of the responses to responsible onsite management. The review included discussions with licensee personnel and observations and review of the items discussed below.

- IEB 83-05, ASME Nuclear Code Pumps and Spare Parts Manufactured by the Hayward Tyler Pump Company (HTPC). The licensee verified that they had no HTPC pumps installed in the plant or maintained in spare parts inventory. This bulletin is closed.

- IEB 82-04, Deficiencies in Primary Containment Electrical Penetration Assemblies. The subject bulletin described deficiencies in certain Containment penetrations manufactured by Bunker Ramo Company. The licensee's response dated March 1, 1983, stated that the bulletin no longer applied to their facility since they had replaced all their Bunker Ramo unitized designed electrical penetrations with Conax Corporation penetrations. This bulletin is closed.

12. Radiological Controls

Radiological Controls were observed on a routine basis during the reporting period. Standard industry radiological work practices, 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 inadequacies were identified.

13. Engineered Safety Features Actuation System Modification

On January 24, 1985, Facility Change Request FCR 84-0095 was implemented on the Unit 1 Engineered Safety Features B Logic cabinet. The purpose of the change was to switch actuation of the High Pressure Safety Injection (HPSI) valves from the B-1 subchannel to the B-2 subchannel and thus delay the opening (by 5 seconds) of these valves following generation of a Safety Injection signal with a loss of offsite power. The modification results in the HPSI valves opening simultaneously with the starting of the HPSI pumps. Section 9 of Inspection Report 50-317/84-31 provides background and details regarding this modification, and how it ensures that 170 gpm is provided to each HPSI piping leg during accident conditions.

During the initial post modification functional test, actuation of the B-1 subchannel still caused the HPSI valves to open. A second test of B-1 and then a test of B-2 showed proper operation (HPSI valves open on B-2 only). The initial failure could not be repeated. Following installation of this FCR on the Unit 1 A-Logic and both Unit 2 logic cabinets, the HPSI valves opened when the cabinets were reenergized. Previous to the modification the valves did not open on cabinet reenergization. The inspector discussed the above events with the Plant Superintendent and General Supervisor, Electrical and Controls (GS,E&C), and recommended further investigation of the cause(s) be conducted. The GS,E&C stated that such investigations would be initiated.

The licensee has not been able to identify the cause of the initial HPSI valve openings during the first test of B-1 on Unit 1. That problem was not repeatable. However, the cause of the HPSI valve openings on both units during cabinet reenergization was a result of powering the HPSI valve actuation relays from one power supply and other B-2 relays from a second power supply. (Both power supply outputs were tied together at a common logic actuation bistable.) Because both of those power supplies are not turned on simultaneously during cabinet reenergizations, transient currents, induced by the momentary voltage

differences between power supply outputs, caused relay/component actuations. A second modification was then performed on each logic cabinet to place all B-2 actuation relays on the same power supply. A check was conducted to ensure that all other Safety Injection Actuation System component relays were powered from the appropriate power supplies. Further testing showed satisfactory system operation.

During licensee investigations for root cause, the following information was identified. First, loss of a single 15 volt power supply in an ESFAS actuation cabinet prevents actuation of several system components. Such a power supply loss, however, is not annunciated in the Control Room nor are the power supplies checked for proper operation (other than during monthly surveillance testing) on a regular basis. Only a total loss of power to a whole ESFAS cabinet is annunciated. Second, during cabinet reenergization, failures of logic modules to reset, after 15 volt power is restored but before 28 volt power is available, would not be indicated to operators (indication is powered by 28 volt power). Inadvertent actuations could then take place as soon as the 28 volt power returned to actuation relays. Inadvertent actuations could be avoided by manually resetting the logic modules before turning on 28 volt power. Third, licensee staff personnel do not know if the ESFAS system is designed to operate as a grounded or an ungrounded system. Improper system grounding could account for the unexplained anomaly. Fourth, consultation by staff design engineers with plant technicians prior to implementation of this design change could have prevented the above problems because at least one technician recognized that all relays in a group should be powered from a common power supply. The inspector recommended to the Plant Superintendent that:

- (1) a requirement to check for proper operation of actuation cabinet 15 volt power supplies be added to operator logs (e.g., once per shift frequency),
- (2) a step be added to ESFAS actuation cabinet reenergization procedures to reset logic modules between turning on 15 volt and 28 volt power supplies,
- (3) grounding requirements for the ESFAS cabinets be determined and a proper grounding be verified, and
- (4) a design change completed in the last year regarding addition of feed-water train trips to ESFAS be reviewed to confirm associated relays are powered by common supplies.

Licensee actions in this area will be followed by the NRC (IFI 317/85-02-02). The licensee's approach to this issue was generally sound. The overall modification, as finally implemented, will improve plant safety. Although the engineering error in splitting group relays between more than one power supply introduced anomalies on system reenergization, it would not prevent system actuation on demand. The design process, however, did lack thoroughness since relay/power supply grouping design requirements were not sufficiently researched.

14. 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:

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

15. 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.