U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Docket/Report: 50-317/88-19 License Nos.: DPR-53
50-318/88-19 DPR-69

Licensee: Baltimore Gas and Electric Company
P. O. Box 1475
Baltimore, Maryland 21203

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

Inspection At: Lusby, Maryland

Inspection Conducted: August 9 - September 12, 1988

Inspectors: D. Trimble, Senior Resident Inspector
V. Pritchett, Resident Inspector
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Approved by: Lowell E. Tripp 9/28/88
Lowell E. Tripp, Chief Date
Reactor Projects Section No. 3A

Summary: August 9 - September 12, 1988: Inspection Report Nos. 50-317/88-19 and 50-318/88-19

Areas Inspected: (1) facility activities, (2) routine inspections, (3) operational events, (4) summer temperatures, (5) maintenance, (6) surveillance, (7) environmental qualification of containment penetration splice connection, (8) radiological controls, (9) physical security, (10) Licensee Event Reports, (11) Region I TI 87-04, (12) reports to the NRC, and (13) licensee action on previous inspection findings.

Results: One violation was identified in which a procedure for defeating and restoring containment air lock door interlocks was not followed resulting in Unit 1 operation without an operable interlock. A more general problem with procedure adherence is evident (detail 3). Other problems identified as the result of this event include (1) the plant staff still is not sufficiently sensitized to the need to document and identify discrepancies found during surveillance testing and (2) more guidelines appear to be needed for the general maintenance order program. Certain types of changes to the plant do not appear to be adequately screened for 10 CFR 50.59 applicability (detail 2). Sufficient guidance to the field is not available with regard to maintenance of instrument air tubing configurations (detail 3). The level monitoring system for the spent resin metering tank is inadequate (detail 5).

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. Night shift inspections were conducted on August 17, 18, 30 and September 9, 1988. Weekend inspections were performed on August 12, 1988.

1. Summary of Facility Activities

Unit 1

On August 13, 1988, with the unit at full power, #11 Main Feed Water Pump (MFWP) tripped. Operators were able to reset the turbine in time to prevent a plant trip. Power was reduced to 70% as a precautionary measure while monitoring #11 MFWP performance. The exact cause of the trip was not identified. The unit was restored to 100% operation on August 18. At 11:38 p.m. on August 24, the unit tripped from 100% power due to a high level condition in #12 steam generator. The high level initiated a turbine trip which in turn caused reactor trip. The high level was caused by a failure in an instrument air supply line to #12 feed water regulating valve, causing that valve to fail open. The plant restarted on August 25 and operated at power for the remainder of the inspection period.

Unit 2

At 10:07 a.m. on August 15, 1988 Control Element Assembly (CEA) #6 dropped into the reactor core. The cause of the drop was identified and corrected, and the CEA was returned to its normal operating position. The unit operated at power for the entire inspection period.

General

On August 16, radioactive liquid was spilled out of a temporary opening in the waste gas header into parts of the auxiliary building as discussed in Detail 5. The spent resin metering tank had been overfilled, and the liquid backed up the vent into the waste gas header.

During the week of August 22, Mr. Bill Borchardt, Senior Resident Inspector at the Salem facility, performed inspections at Calvert Cliffs.

On August 23, a senior management meeting was held in Rockville, Maryland between Messrs. E. Crooke and J. Tiernan of Baltimore Gas and Electric Company and W. Russell and T. Murley of the NRC.

During the week of August 29, Mr. Ed Yachimiak, an NRC examiner/inspector from the Region I office, conducted an inspection of the licensed operator requalification program.

On September 1, the Nuclear Maintenance Department was combined with the Nuclear Operations Department. Mr. L. Russell was promoted to Manager-Calvert Cliffs Nuclear Power Plant.

2. Review of Plant Operation - Routine Inspections (71707)

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

-- Diesel Generator #12 Air Start System checked on August 19, 1988

-- Unit 2 Service Water System on August 24, 1988

No unacceptable conditions were noted.

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. Plant housekeeping and cleanliness were evaluated.

Review of 50.59 Process for Non-Safety Related Equipment

A review was completed of the Calvert Cliffs process for evaluating changes to non-safety related (NSR) items to ensure compliance with 10 CFR 50.59. A review of the Quality Assurance Manual, including the QA Policy and Procedures and the Calvert Cliffs Instructions CCI-126G, CCI-200J, and CCI-700A was completed. The QA policy dictates that "Design changes to NSR items initiated and approved at the plant are controlled to ensure compliance with 10 CFR 50.59". Design changes are evaluated with respect to 50.59 during the Field Change Request (FCR) process. Quality Assurance Procedure, QAP-15, provides the controls to ensure that changes, tests, and experiments conform to 10 CFR 50.59. Changes, test and experiments are classified into seven catagories per QAP-15. Category 3 includes design changes to structures, systems and components classified as NSR and not described in the FSAR (FCR optional). The FCR was made optional in order to streamline the design change process. However, without an FCR, it is not clear that a 50.59 applicability evaluation will be completed. A maintenance request, and subsequent maintenance order could potentially be completed with no 50.59 applicability review completed. As a result, changes could be made to NSR equipment which could impact the ability of safety-related equipment to perform its function. Without the 50.59 evaluation the impact could remain unidentified. In addition, if a design change is incorrectly identified as NSR, the potential exists to modify safety-related equipment without an FCR or 50.59 evaluation. The licensee is evaluating corrective actions, the inspectors will follow resolution of this issue.

3. Operational Events (93702)

Inoperable Containment Air Lock Door Interlock

About 6:30 p.m. on August 16, 1988, technicians performing a surveillance test procedure (STP M-471-1, Air Lock Door Operability and Leak Rate Test) on the Unit 1 Containment Air lock discovered that one of two interlocks associated with the air lock was defeated. Defeating either one of the interlocks permits both doors to be opened simultaneously.

Technical Specification (TS) 3.6.1.3 requires the air lock to be operable in Modes 1 through 4. Unit 1 was in Mode 1 operation at the time and both doors were shut. TS surveillance requirement 4.6.1.3c requires the air lock to be demonstrated operable at least once per 6 months by verifying that only one door in the air lock can be opened at a time.

The Shift Supervisor (SS) was informed of the inoperability and entered an action statement (3.6.1.3.a) for an inoperable air lock at 6:30 p.m. Apparently communications between the technicians and the SS were weak in that the SS believed only a minor problem had been found with the interlock. In fact, one interlock was found to be physically defeated (by means of a spring being disconnected from an engagement pawl and a wooden wedge to hold the pawl in a disengaged position). Often during plant outages, one interlock is defeated to permit both doors to be opened. Because the nature of the inoperability was not communicated to the SS, he did not recognize its significance and raise it as a concern to plant management. The SS did not further question the technicians to determine the nature of the problem. Mechanical maintenance personnel were notified and restored the interlock to an operable status. The TS action statement was exited at 9:10 p.m. on August 16. The site's surveillance test program procedure, CCI 104H, Appendix 104.30 requires that each out of specification condition, malfunction, or adjustment be described briefly in the remarks section of the STP cover sheet. The remarks entered were "Failed Section II.20.A. Door operability adjustments performed by mechanical group." Section II.20.A tests one of the two interlocks. Section II.20.A was not signed off as completed until the following day, August 17, after technicians returned and completed that test. The remainder of the procedure was signed off by the technicians on August 16.

The completed procedure is not required to be reviewed by the SS. It is reviewed by the technicians' supervisor. During this review, again the significance of the problem was missed by poor communications and/or the relatively innocuous remarks on the cover sheet. In early September a systems engineer reviewed the completed procedure, questioned technicians about the problems encountered, and made the Plant Operations and Safety Review Committee (POSRC) aware of the defeated interlock. The licensee then initiated further investigation of the event to determine when the interlock was defeated and identify weaknesses and root causes.

In April 1988, while Unit 1 was shut down for a refueling outage and air lock operability was not required, both interlocks were defeated. This was contrary to the procedure under which this was accomplished, HE 21. That procedure only directed that one of the interlocks be defeated. The mechanic and QC inspector involved indicated that there was a note in the procedure which mislead them into thinking both interlocks should be defeated. On June 25 a different mechanic assigned to re-establish the interlock, assumed that per HE 21 only one interlock was defeated. He then restored only one interlock. He knew that HE 21 then required that a test be performed to confirm that both doors could not be opened simultaneously. However, he performed such a test in a manner different from that described in the procedure. The procedure called for opening one door and then trying to open the second. He only rotated the hand wheel for one door about a turn (not sufficient to unlatch and begin opening the door) and then tried to open the second door. The second door would not open, and he and a QC inspector signed off the test as being satisfactorily completed.

The failure of mechanical maintenance personnel to follow procedure HE 21 in both defeating and restoring the interlocks is a violation (317/88-19-01). This event, as well as others described below, indicate a more general weakness regarding plant staff adherence to procedures. For example, on October 30, 1987, STP 0-5-1, Auxiliary Feed Water System surveillance test, was deviated from without first properly making temporary changes to the procedure (Violation, Inspection Report 50-317/88-01, 50-318/88-01). On February 1, 1988, following a fire in an annunciator cabinet, portions of Emergency Response Implementing Procedure 3.0, "Immediate Actions", were not implemented (Violation, Inspection Report 50-317/88-04, 50-318/88-05). On March 30, 1988, a procedural and TS limit of 400 degrees F temperature differential between the Unit 2 pressurizer and its spray line was allowed to be exceeded (Inspection Report 50-317/88-05, 50-318/88-06). On April 4, 1988, three changes were made to surveillance test procedure STP M529-1 Containment Pressure Calibration, without proper approval (Violation, Inspection Report 50-317/88-07, 50-318/88-08). At the end of the inspection period, escalated enforcement action was pending regarding failures to follow procedures regarding improper calibration of delta T power and mispositioning of a diesel voltage regulator speed mode switch (Inspection Report 317/88-17, 50-318/88-17).

The fact that QC inspectors did not identify procedural noncompliances for the above interlock event is a weakness.

Other weaknesses were also identified by the event. The failure of the technicians to clearly identify the nature or significance of the interlock problem to the SS or their management indicates that they have not been sufficiently sensitized to a principle purpose of surveillance testing, which is to identify any discrepancies in equipment operation so that actions may be taken not only to correct the immediate problem but also to prevent recurrence. The failure of the SS to further question technicians on the details of the problem indicates a similar weakness. The defeating/restoration of the interlocks was done under a general maintenance order which is active for a one month period and is intended for minor maintenance and troubleshooting activities (to reduce administrative paperwork for small activities). The work is done by an experienced "rover" mechanic. The guidelines associated with this maintenance order appear to be too vague. They could be interpreted to allow any work on safety related or non-safety related equipment with the only restrictions being that (1) no work involving tagouts is permitted, (2) the SS must be informed of work on a daily basis before it is performed, and (3) replacement parts are limited to only those in free stock (principally small fittings). It raises the possibility for installing parts not meeting code requirements in code class systems. Licensee personnel responsible for establishing programs to ensure only code class material is used were not aware of the "rover" program.

Finally, the general maintenance order is a poor way of tracking items such as the defeating of interlocks since it is only reviewed for incomplete activities at the end of a month period. The interlocks may be required well before the end of the month.

CEA Drop

On August 15, 1988, at 10:07 a.m., Unit 2 experienced a rod drop into the core of Control Element Assembly CEA-06. Power level was at 72%. The rod drop resulted in a 90 MW drop from 640 MW to 550 MW. The operators entered AOP-1B "CEA Malfunctions" and Technical Specification Action Statement 3.1.3.1.f. Technical Specification (TS) 3.1.3.1.f allows temporary operation in Modes 1 and 2 with one CEA misaligned from any other CEA in its group by 15 inches or more provided that the CEA is positioned within 7.5 inches of the other CEA's in its group in accordance with the time allowance in TS Figure 3.1-3 "Allowable Time to Realign CEA vs Initial Total Integrated Radial Peaking Factor". The initial integrated radial peaking factor is the measured pre-misaligned total integrated radial peaking factor. The allowable time for realignment was determined to be 47 minutes. The cause of the drop was determined to be a lifted lead in the CEA-06 15 volt power supply. The lift occurred when an instrument and controls planner entered the back of the Control Element Drive System (CEDS) panel to scope out a maintenance request. The CEDS logic panel, located in the cable spreading room, contains power supply cabling for the individual rods. Cabling in the panel is attached to the back door of the panel by a cable harness. It was determined that there was too much tension on the cabling in the harness and that when the planner opened the door, the CEA-06 power supply lead lifted from the contact. As a result, power was deenergized to the CEA-06 coils and the CEA dropped into the core. Following determination of the cause, the lead was repaired and the cables in the panel were loosened from the door to prevent reoccurrence. Other contacts in the panel were examined to determine if any loosening had occurred. Upon completion of the repair, the operators commenced withdrawing CEA-06 at 10:30 a.m. AOP-1B was exited at 10:47 a.m. when CEA-06 was aligned with its group. The licensee plans to check all of the CEDS panels for cable tension and loose wires at the next refueling outage.

Unit 1 Reactor Trip on High Steam Generator Level

At 11:38 p.m. on August 24, 1988, Unit 1 tripped from 100% power due to high steam generator level in #12 steam generator (SG). Feedwater Regulating Valve (FRV #12) had failed open following a severing of an instrument air (IA) supply line to the valve's positioner. This resulted in excess feedwater flow to #12 SG. Immediately prior to the trip operators unsuccessfully tried to take manual local control of the valve and to reduce main feedwater pump speed.

Plant conditions were quickly stabilized. Pressurizer level and pressure decreased during the transient to values below those normally experienced during trips, but this did not significantly aggravate the transient. Pressurizer level reached about 50 inches (normal post trip level is about 80 inches), and pressurizer pressure reached 1800 psia (normal post trip value is about 1900 psia).

Operators were first alerted to the condition by a computer alarm warning of high steam generator level. By procedure (Abnormal Operating Procedure 3G) operators are to manually trip the plant at the +50 inches level. This is the same point at which an automatic trip of the turbine generator is initiated. The turbine generator trip in turn causes reactor trip.

The air line broke at the point where the IA line attaches to the valve positioner. This point acted as a support point for a pressure switch upstream in the IA line. This apparently led to vibration induced cyclic flexure in the line and ultimate line failure.

Before the spring refueling outage on Unit 1, systems engineers had identified the fact that the pressure switches for both FRV's were not adequately supported and had initiated a maintenance order to move those switches further upstream and to provide better supports for them. This had been completed for FRV #11; but, due to outage time or manpower constraints, was not completed on FRV #12. The switches are adequately supported on Unit 2 FRV's.

On September 7, 1987 Unit 2 tripped due to a failed instrument sensing line (fatigue failure from vibration) for a pressure transmitter associated with the turbine electro-hydraulic control system. Following that event some system walk downs were initiated to identify vibration problems in piping. Tubing problems such as in the FRV's were not identified as problems by that effort.

The licensee conducted an additional survey of instrument tubing and IA lines in the secondary plant for both units after the FRV event. At the close of the inspection period the results of that survey were being prepared for management review.

In general, IA tubing configurations to supplied components are not shown on specific prints. Tubing was installed in accordance with general specifications or typical configurations provided in Drawing M500. An individual from the licensee's QA group, who was tasked with reviewing the details of the event and recommending corrective actions, stated that M500 may be too vague and not easily applied by repair personnel. The NRC inspectors concluded that restoration of tubing to original configurations following maintenance activities is therefore essential unless engineering is consulted. The inspectors learned that there is not a clear understanding between the I&C and mechanical maintenance groups regarding who is responsible for disassembly/restoration of IA tubing during maintenance. Furthermore there was no written guidance to, at least, I&C personnel to ensure that original tubing configuration is maintained.

The controls over tubing configurations (design and maintenance) appear weak. The inspectors raised this concern to plant management. The inspectors will review future corrective actions taken by the licensee in this area.

No unacceptable conditions were noted.

4. Impact of Summer Temperatures

Unusually hot weather during the month of August posed two potential problems for Calvert Cliffs: one concerning containment ambient temperatures, the other concerning water system inlet temperature. The measured containment ambient temperature limit per plant technical specifications is 120 degrees F. Containment temperature for Unit 2 during the month remained just under the 120 degrees F limit. A relief from the TS temperature limit was considered but Baltimore Gas and Electric Company decided to refrain from pursuing the change due to the extent of the analysis required to support environmental qualification of safety-related equipment. Equipment aging calculations for equipment inside containment are based on the 120 degrees F ambient temperature. As a result, the effects of the increased temperature limit would have to be evaluated for all equipment inside containment. Containment temperature limits were not exceeded during the inspection period.

The second potential problem posed by the high temperature was an increase in Chesapeake Bay water temperature. The bay is Calvert Cliffs' ultimate heat sink and supplies the plant's salt water systems. The salt water systems cool the service water heat exchangers, the component cooling heat exchangers and the emergency core cooling system (ECCS) pump room coolers. The post-accident cooling capability of the service water heat exchangers was calculated based on a salt water inlet temperature of 85 degrees F.

Using the 10 CFR 50.59 process, the licensee increased the allowable bay temperature to 87.5 degrees F. This was completed by determining the maximum service water temperature that would provide for removal of the most limiting accident heat loads. An allowable service water temperature of 105 degrees F was calculated. A corresponding salt water inlet temperature of 87.5 degrees F was calculated based on service water heat exchanger heat transfer. The licensee evaluated the potential effects of the 105 degree F service water temperature on the essential equipment cooled by the system. It was determined that the only equipment of concern was the diesel generators. The diesel generator manufacturer had been queried in the 1970's concerning the effects of 105 degree F temperature on diesel generator operability. A 1977 letter from the manufacturer indicates that the diesels will perform their function with the 105 degree F temperature as long as the coolers are perfectly clean. The letter further indicates that since perfectly clean coolers are not a realistic situation, the diesel could perform their function at near full load for a short period of time. No definition of "near full load" or "short period of time" was given. The licensee did not further question the acceptability of the 105 degree F temperature at near full load or for a short period of time because the greatest heat loads occur only post-LOCA for only a short period of time. A more definitive evaluation of the 105 degree F service water water temperature on the operability of the generators is needed. The licensee agreed to evaluate this in conjunction with the plant overall cooling study being conducted by design engineering. The study is expected to be complete by March 1989. The inspector asked to be kept informed of the results of the evaluation. This item is unresolved pending satisfactory completion of the evaluation (317/88-19-02).

The effect of the increased temperature on the component cooling water system was evaluated by bounding the problem at the component cooling water heat exchanger. Although FSAR Section 9.5.2.1 refers to a saltwater inlet temperature of 85 degrees F, it indicates a component cooling water outlet temperature of 95 degrees F. The 95 degree F component cooling water temperature limit was determined to be maintained with the higher salt water inlet temperature. This was based on the fact the component cooling water is secured until the recirculation phase of a LOCA. Limiting accident heat loads occur post-LOCA prior to recirculation.

The ECCS pump room coolers were also determined to be unaffected by the temperature change due to the margin in the cooling capability of the room coolers versus the potential corresponding room heat load.

No adverse effects of the increased temperatures on electrical equipment were identified.

5. Plant Maintenance (62703)

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, fire protection, retest requirements, and reportability per Technical Specifications. The following activities were included:

-- PM 1-24-M-2W-2, #12 Emergency Diesel Engine Leak Inspection observed on August 18, 1988

-- PM 1-24-I-Q-115, #12 Diesel Room Supply and Exhaust Dampers and Controls observed on August 18, 1988

Beginning August 16, 1988, during the day shift, maintenance was being performed to clean the Waste Gas Discharge Header radiation monitor 0-RE-2191. The day shift was unable to complete the maintenance and received permission from the shift supervisor to leave the monitor open. During the swing shift that evening, resin was transferred from the No. 11 Chemical Volume and Control System Ion Exchanger to the Spent Resin Metering Tank. Following the transfer, during procedure required health physics surveys, a 25 R/hr hot spot was detected in the transfer lines in the Reactor Coolant Waste Metering tank room. The room was posted as a locked high radiation area and the control room was notified. In order to eliminate the hot spot, the transfer lines were flushed. The spent resin metering tank is vented through the Waste Gas Discharge Header radiation monitor to the Main Plant Vent. During the course of the flush, the spent resin metering tank overflowed into the tank vent line and subsequently out the open radiation monitor onto the 69 foot elevation floor outside the Unit 2 containment entrance. The water spilled both into previously contaminated and uncontaminated areas inside controlled access boundaries. In addition, the water flowed down the wall into the 45 foot elevation directly below the 69 foot elevation. The spill was discovered during a routine walkdown by an auxiliary building operator. Maximum contamination was determined to be 80,000 dpm. Cleanup was completed over the following two day period. No unexpected personnel exposure occurred. The cause of the problem was determined to be lack of reliable level indication in the spent resin metering tank. The originally installed bubbler indicating alarm has never worked properly. In addition, a newly installed ultrasonic level indicator has never worked properly. There are several outstanding FCR's attempting to address the problem. However, no resolution is currently in place. Operating Procedure OI-17A, used to perform the resin transfer, contains a caution statement not to exceed 90 inches in the spent resin metering tank. Without adequate level indication, the operators are in the position of potentially violating the procedure every time a transfer occurs. Should a spill occur during an actual resin transfer the dose and clean up consequences could be much more severe. The inspector will continue to follow this issue until resolution is achieved.

No other unacceptable conditions were identified.

6. Surveillance (61726)

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 0-8-B-1, #12 Diesel Generator and 4KV Bus 14 LOCI Sequencer Test observed on August 18, 1988

-- STP 0-90, Units 1 and 2 Breaker Lineup Verification observed on August 18, 1988

-- Performance Evaluation, CCI 363D, OI-21 Overspeed Test observed on August 18, 1988

-- STP 0-87-2, Borated Water Source Operability Verification observed on August 19, 1988

-- STP 0-7-2, ESFAS Logic Test observed on August 19, 1988

-- STP 0-71-2, Staggered Test of "B" Train Components - Containment Cooling Units 23 and 24

-- STP 0-8A-2, #12 Diesel Generator and 4 KV Bus 21 LOCI Sequencer Test

No unacceptable conditions were noted.

7. Containment Penetration Splice Connection Found Not Environmentally Qualified on Unit 1 (93702)

During a comprehensive inspection of environmentally qualified splice connections in accordance with IE Bulletin 79-01B, a quality control inspector discovered an unqualified splice on April 15, 1987.

A maintenance order was initiated to upgrade the splice connection to meet the licensee's environmental qualification standards. An electrician did not see the unqualified splice and instead believed the maintenance order was intended to repair or replace a cracked cable connected at the same penetration. The electrician disassembled and remade an environmentally qualified connection on an adjacent cable. No action was taken on the unqualified splice connection. The maintenance order was reviewed by a qualified environmental qualification engineer and accepted for operation.

On June 13, 1988, while in Mode 5, at a Reactor Coolant System pressure of 230 psia and temperature of 120 degrees F, an inspection of the Unit 1 type 2A and 2B Amphenol containment penetrations was conducted to confirm the presence of conformal coating on these penetrations. During the course of this inspection, it was discovered that the splice connection for #11 containment air cooler appeared deficient in that the Raychem heat shrink material was split and covered with electrical tape. Calvert Cliffs engineering personnel reviewed the connection and declared that it was not environmentally qualified at 3:00 p.m. on June 13, 1988. Operations was notified at 6:00 p.m. that date, and the equipment declared inoperable.

The as-found condition of the splice connection did not affect the function of #11 Containment air cooler during normal operations.

The cause of the event was personnel error during the 1987 environmental qualification inspection when the deficiency was noted, but not corrected.

The safety consequences of this event are reduced because of the following considerations. While the splice connection at the penetration for #11 containment air cooler remained unqualified, the connections for the other three containment air coolers were qualified at that time. In the event of a loss of coolant accident, a main steam line break or feed water line break inside containment, other containment air coolers and two trains of containment spray were available for reducing containment temperature and pressure.

The connection was disassembled and remade as part of Facility Change Request 88-90 in accordance with Calvert Cliffs environmental qualification standards. The equipment was tested and returned to service on June 23, 1988. Corrective action also included inspection of Unit 2 type 2A and 2B Amphenol containment penetrations containing environmentally qualified circuits. No discrepancies in connections were discovered in this inspection conducted by engineering personnel on June 27, 1988.

The issue of containment penetration splice connection found not environmentally qualified and not promptly repaired is a licensee identified violation in accordance with Section V of Appendix C, 10 CFR 2 (317/88-19-03).

8. Radiological Controls (71707)

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.

No unacceptable conditions were identified.

9. Observation of Physical Security (71707)

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.

10. Review of Licensee Event Reports (LERs) (90712 and 92700)

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			
88-04*	06/13/88	07/13/88	Containment Penetration Splice Connection Found Not Environmentally Qualified, Caused by Incomplete Maintenance and Engineering Review
88-06	07/15/88	08/15/88	Loss of Load Due to Unclear Maintenance Procedure

*Detailed examination of this event is documented in detail 7 of this inspection report.

No unacceptable conditions were noted.

11. Bypass of Non-Essential Diesel Generator Trips (Region I Temporary Instruction 87-04)

The inspector conducted a review of diesel generator logic drawings, the FSAR, and applicable surveillance test procedures to verify that non-essential diesel generator trips are automatically bypassed during both Loss of Coolant Accident (LOCA) and Loss of Offsite Power (LOOP) conditions. Each diesel generator is provided with the following trips:

-- start failure
-- engine overspeed
-- high jacket coolant temperature (2/3 logic)
-- low jacket coolant pressure (2/3 logic)
-- low lubricant oil pressure (2/3 logic)
-- high crankcase pressure (2/3 logic)
-- loss of generator field if paralleled
-- generator differential
-- generator ground over current

The low jacket coolant pressure and the high jacket coolant temperature trips are considered non-essential trips and are therefore automatically bypassed in the event of either a LOCA and/or a LOOP. The automatic bypass function is verified at least once per 18 months by surveillance test procedure STP-M-651 "Diesel Generator Trip Bypass on SIAS" in accordance with Technical Specification requirement 4.8.1.1.2.d.3.c. The inspector reviewed the most recent test results and found the results to be acceptable. No problems were identified with the diesel generator trip logic scheme.

No violations were identified.

12. Review of Periodic and Special Reports (90713)

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 report(s) was/were reviewed:

-- July Operating Data Reports for Calvert Cliffs No. 1 Unit and Calvert Cliffs No. 2 Unit, dated August 16, 1988.

-- Report of Startup Testing for Unit 1 Cycle 10, dated September 9, 1988.

No unacceptable conditions were identified.

13. Licensee Action on Previous Inspection Findings (93702 and 92701)

(Closed) Violation (318/84-17-01) Deficiency in Administration of Employee Screening Program. The deficiency was corrected. This item is closed.

(Closed) Inspector Follow Item (318/83-31-02) Licensee to Include Procedure Requirement to Check both Types of Indications of Control Element Assembly (CEA) Position on CEA Movements. Operating Instruction OI-42, Rev. 14, regarding CEA operations now requires that CEA positions be checked using both the primary and secondary types of indications. This item is closed.

(Closed) Unresolved Item (318/83-02-01) Contrary to TMI Action Plan Item II.F.2.1.A Both Subcooled Margin Monitors (SCMM) on Each Unit Share a Common Power Supply. The two SCMM's on each unit now have separate power supplies. For example, on Unit 1, SCMM #11 receives power from vital A.C. bus 1Y01. Bus 1Y01 is powered in turn by inverter 1Y01A which normally is fed by battery bus #11. SCMM #12 receives power from vital A.C. bus 1Y02. Bus 1Y02 is powered by inverter 1Y02A which is normally fed by battery bus #21. Both inverters have the capability of being manually selected to backup power supply bus 1Y11. Bus 1Y11 is an engineered safety bus which is backed by an emergency diesel generator. This item is closed.

(Closed) Inspector Follow Item (317/88-03-01;318/88-03-01) Measurement Control Evaluation Nonradiological Chemistry. On completion of the analyses of water samples (spiked samples) by the licensee and Brookhaven National Laboratory, a statistical evaluation was to be made. The analyses were completed and an evaluation was performed. The analytical comparisons for the analyses were acceptable.

Analytical Results of Spiked Split Samples

Analysis	Matrix	Sample ID	Calvert Cliffs	Brookhaven
Floride	S/Generator	0.1ml spike	3.1 ppb	4.5+/-0.2ppb
		0.4ml spike	19.3 ppb	17.6+/-0.2ppb
Chloride	S/Generator	0.1ml spike	12.3 ppb	<10 ppb
		0.4ml spike	24.6 ppb	18.3+/-0.6ppb
Sulfate	S/Generator	0.1ml spike	11.7 ppb	16.9+/-0.1ppb
		0.4ml spike	29.8 ppb	28.2+/-1.6ppb
Iron	S/Generator	1.0ml spike	<10 ppb	<10 ppb
		2.0ml spike	<10 ppb	16.9+/-0.1ppb
Copper	S/Generator	1.0ml spike	11.2 ppb	12.0+/-0ppb
		2.0ml spike	22.4 ppb	28.0+/-0ppb
Boron	Duke Cross-Check(1)	none	1873 ppm	1998+/-29ppm

(1) Expected boron concentration was 1920 ppm, but the standard preparation was not satisfied due to dissolution of the crystal. The cross-check standard was prepared by Duke Power Company.

14. Unresolved Items

Unresolved items require more information to determine their acceptability and one such item is discussed in detail 4 of this report.

15. Exit Interview (30703)

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.