U.S. NUCLEAR REGULATORY COMMISSION
REGION I

Report Nos.: 50-317/89-14
50-318/89-14

Docket Nos.: 50-317
50-318

License Nos.: DPR-53
DPR-69

Licensee: Baltimore Gas and Electric Company
Post Office Box 1475
Baltimore, Maryland 21203

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

Inspection At: Lusby, Maryland

Inspection Conducted: May 16 - July 3, 1989

Inspectors: H. Eichenholz, Senior Resident Inspector
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Approved by: Lowell E. Tripp 8/24/89
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Reactor Projects Section No. 1A

Inspection Summary: May 15 - July 3, 1989
Inspection Report Nos. 50-317/89-14 and 50-318/89-14

Areas Inspected: Facility activities, licensee action on previous inspection findings, operational safety, physical security, plant operations, maintenance, surveillance, ATWS rule implementation, engineering support, Licensee Event Reports, licensee response to NRC initiatives, review of periodic and special reports, and events requiring notification to the NRC.

Results: There were multiple examples of a failure to satisfy 10 CFR 50, Appendix J penetration leak rate testing requirements in a timely manner (see Section 7.2). The licensee continued to investigate pressurizer heater failures to determine the failure mode (see Section 6.1). A stuck fuel assembly was removed satisfactorily with proper safety perspective displayed (see Section 6.3). Similarly, a prudent safety approach was taken in defueling the reactor with the degraded pressurizer conditions (see Section 6.1). These are positive trends.

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* The NRC Inspection Manual inspection procedure (IP) or the Region I temporary instruction (RTI) that was used as inspection guidance is listed for each applicable report section.

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. Night shift inspections were conducted on May 31, June 13, 14 and June 28, 1989.

Weekend inspections were conducted on June 25, 1989.

2. Summary of Facility Activities

Unit 1

The unit was shut down the entire period pending the results of the pressurizer heater investigation being conducted for both units.

Unit 2

The unit was shut down for the entire period for the 8th cycle refueling outage. The unit will remain shut down pending results of pressurizer heater investigation and subsequent repairs.

General

Members of the Union of Soviet Socialist Republic Committee for Supervision of Nuclear Power Safety visited the facility on May 17, 1989.

Region I specialist inspection personnel performed inspections during the following time periods:

- May 15 - May 26, 1989, Emergency Operating Procedures
- May 22 - May 26, 1989 and June 12 - June 16, 1989, Followup inspection for findings identified in NRR Special Team Inspection (89-200).

The licensee met with the NRC in King of Prussia, on May 30, 1989, for an enforcement conference resulting from findings of Combined Inspection Report Nos. 50-317/89-11 and 50-318/89-11.

The licensee met with the NRC at NRC Headquarters on June 19, 1989, to discuss the status of Calvert Cliffs Units 1 and 2.

Defueling operations began on Unit 2 on June 23, 1989, by the end of the inspection period, 183 out of 217 assemblies had been removed.

3. Licensee Action on Previous Inspection Findings

3.1 (Closed) Unresolved Item 50-317/88-23-01; 50-318-88-23-01

Offsite Safety Review Committee (OSSRC) charter and membership concerns. The licensee has removed two of the three members from the Plant Onsite Safety Review Committee (POSRC) who concurrently held positions in the OSSRC. The Manager of Calvert Cliffs Nuclear Power Plant Department (CCNPPD) continues to serve on the OSSRC. Additionally, the licensee has revised the composition of the OSSRC such that only one current OSSRC member, the Manager - CCNPPD, is part of the onsite operating organization. This item is closed.

3.2 (Closed) Violation 50-318/89-04-01

Failure of Control Room personnel to summon the Fire Brigade to a fire in a control room panel. The licensee's response to the violation dated June 9, 1989, indicated that the licensed operators were counseled in the importance of strict adherence to procedures, and that the Emergency Response Plan Implementing Procedures (ERPIP) contain no latitude with respect to the required response to a fire. Additionally, the licensee restated their commitment to assure procedural compliance. This commitment is one of the top priorities of the Performance Improvement Plan. As noted in Section 4.1 of this report, minor plant incidents involving fires, or overheated components, resulted in timely and proper response by the fire brigade in accordance with established procedures. This violation is closed.

4. Operational Safety

4.1 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.

On May 16, 1989, a fire occurred in a welding machine near the Unit 2 Amertap panel. Shortly after the fire was reported it was extinguished. In accordance with ERPIP 3.0, the emergency alarm was sounded and the fire brigade summoned. The inspectors observed licensee emergency response activities in the control room and out in the Unit 2 portion of the turbine building. Licensee response was fully in accordance with procedural requirements, with activities being performed in a timely and professional manner. It appears that licensee corrective actions to a prior NRC concern involving failure to announce a fire and assemble the fire brigade were effective.

4.2 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 during plant tours and control room panel status observations:

- Unit 1 Service Water System
- #12 Diesel Generator Air Start System
- Unit 1 and 2 Shutdown Cooling System

No unacceptable conditions were noted.

4.3 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 was reviewed. Plant housekeeping and cleanliness were evaluated.

On May 24, 1989, the licensee's Safety and Fire Protection Unit at the plant received a multi-purpose fire engine that is equipped to handle fires, medical emergencies and hazardous material incidents on licensee property The licensee's enhancement to it's fire protection and prevention activities is indicative of their generally strong performance in this area.

No unacceptable conditions were identified.

5. Security

5.1 Observation of Physical Security

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

No unacceptable conditions were noted.

6. Plant Operations

6.1 Unit 2 Pressurizer Heater Defects

Following the initial investigation of Unit 1 and 2 Pressurizer Heater Penetration defects (see combined Inspection Report 50-317/89-06 and 50-318/89-06, Section 6.4), the licensee developed a safety evaluation to ensure that the conduct of refueling operations would not result in an unreviewed safety questions consistent with the requirements of 10 CFR 50.59. On May 24, 1989, the Plant Operations and Safety Review Committee (POSRC) approved the safety analysis to allow defueling operations on June 2 with the following restrictions/limitations:

(1) Minimum refueling water level
(2) Frequent leakage checks
(3) Limited work to prevent bumping heaters
(4) Ensure operators were aware of plant conditions and were prepared to take action
(5) Define a required RWT volume
(6) Required containment floor to be clear of debris
(7) No fuel assemblies are to be in a raised position in the Spent Fuel Pool.

The initial project plan was specified and distributed on June 1, 1989, and preparations, prestaging and initial work on Unit 1 began on June 12, 1989. Inconel 690 pressurizer heater sleeve material was ordered on June 14, 1989, in the event that sleeve replacement were required. On June 22, 1989, two heaters were removed from the Unit 1 pressurizer. Eddy current testing of the Unit 1 sleeves showed no indications. The sleeve to clad J-welds on Unit 1 were not inspected due to a hard deposit buildup around the weld area.

Defueling operations began on June 23, 1989, and preparations for initiation of work on Unit 2 pressurizer heaters was in progress at the end of the inspection period with work to begin once defueling was completed.

The inspectors will follow the licensee corrective action program and will update progress in subsequent reports.

6.2 Appendix R and Fire Protection Related Issues

- In January 1989, the licensee initiated efforts to perform a programmatic overview of 10 CFR Part 50, Appendix R compliance. One objective included a review of the basis of the procedure AOP-9, Alternate Safe Shutdown. In April 1989, it became questionable as to whether the minimum available number of operations personnel on a shift crew could implement AOP-9 during a

fire emergency. On May 15, 1989, with both Units in shutdown, a walk-through of AOP-9 was conducted, which resulted in an assessment that there was not adequate assurance that sufficient shift staffing was available on all shifts to implement AOP-9 as written. The licensee notified the NRC on May 19, 1989 of the potential staffing problems and on June 21, 1989, a determination was made that this condition was reportable in accordance with the requirement of 10 CFR 50.73. This event will be discussed further in LER 50-317/89-009

The discovery of the existence of this concern evolved out of the licensee's initiative to form a Configuration Management Unit in the Design Engineering Unit of the Nuclear Engineering Department. This Unit has been assigned the task of consolidating the plant's design basis to enhance their ability to assess the impact of proposed plant activities on the design basis. This resulted in the assignment of a fire protection engineer (FPE) to aid in consolidating the site fire protection program and providing long-term programmatic overview of 10 CFR Part 50, Appendix R compliance. To assist the FPE in performing the initial objective of verifying and clarifying the basis of the AOP-9 procedure, a project team of design, operations, quality assurance, systems, and licensing engineers was assembled. Their efforts resulted in identifying a number of discrepancies that could potentially preclude bringing both units to a safe shutdown condition during a worse-case Appendix R fire without exceeding the acceptance criteria in 10 CFR Part 50, Appendix R, Section III.L. Besides the question of the adequacy of the staffing levels, equipment concerns involving the atmosphere dump valves and procedural deficiencies were identified.

On May 23, 1989, the licensee transmitted to the NRC their Unit 1 and 2 restart commitment that specified that the concerns involved with the identified deficiencies associated with this event will be addressed before startup of either unit. Additionally, the licensee plans a meeting with appropriate NRC staff to review program initiatives in this area, significant findings and methods of resolution of identified deficiencies.

The inspector had no further questions at this time.

- On May 22, 1989, the licensee's FPE discovered a fire damper in the closed position on Unit 2 while performing a walkdown of the penetration ventilation exhaust system fire dampers. The Unit was in Mode 6 at the time of the discovery, with the ventilation system required to be operable in Modes 1-3.

The damper was found in the closed position due to the failure of its fusible link. This condition could have prevented the penetration ventilation system from being operable. Following the discovery of this condition, an air flow test of the penetration exhaust system using Surveillance Test Procedure (STP) M-544 was performed. This 18 month surveillance test resulted in identifying that the test, as written, would not account for or detect the closed damper. In fact, with the damper closed, satisfactory test results were achieved. A review by the licensee of prior surveillance tests indicated that the test results were similar to the tested condition with the damper closed. A subsequent test with the damper open resulted in identifying an unacceptably high flow rate.

Initially, the licensee's systems engineers considered STP M-544 adequate because the proper performance first of STP M-592-2, Penetration Fire Barrier Inspection, would have identified the closed position of the damper, caused the damper to be opened, and allowed the unsatisfactory high flow condition to be identified and corrected. The inspector expressed concerns to the cognizant licensing engineer that it would be considered unacceptable to consider that STP M-544 was adequate as written in that it was not able to demonstrate the design function of the system with the damper closed. The licensing engineer acknowledged and agreed with the inspector's concerns, and was able to facilitate the systems engineer's understanding of the issue to agree that corrective action was appropriate.

Based upon their analysis of this event and review of prior system performance, the licensee was unable to determine how long this condition could have existed in Unit 2. Corrective actions will include: (1) determining if fusible links should be periodically replaced; (2) verify the adequacy of STP M-544; (3) verify surveillance for other safety related ventilation systems are ensuring the systems are meeting their design function; and (4) review the surveillance testing program for generic concerns relative to testing design function. The licensee will be further documenting this event and their corrective actions in LER 50-318/89-009.

In a related matter, licensee identified inadequacies associated with the failure to perform SPT M-592-2 in a timely manner is addressed in Section 7.2 of this report.

This event points out that the licensee's efforts to ensure compliance to the established fire protection program requirements is functioning due to the active involvement of a dedicated FPE. In this regard, the licensee's efforts to self identify and correct deficiencies in a timely manner is viewed as a positive aspect of an apparent high level of licensee commitment to provide a proper level of engineering support in this area.

- On June 30, 1989, the licensee conducted the fire barrier penetration inspection in accordance with STP M-592-1. During the conduct of the STP, the FPE discovered a fire damper was physically missing in the spent fuel pool ventilation system. The licensee's shift supervisor was notified and entered the appropriate TS action statement. The licensee made appropriate notification to the NRC and plans on submitting a LER (50-317/89-11) to describe the event, it's root cause, and corrective measures. The NRC will review this matter as part of LER followup activities.

6.3 Stuck Assembly in Core Location T-20 During Defueling Operations of Unit 2

On June 25, 1989, at approximately 3:00 a.m., the licensee experienced problems during attempts to remove fuel assembly 2H018 from core location T-20. Bridge and trolley coordinates were adjusted within guidelines allowed by FH-6, "Core Refueling Procedure". The affected fuel assembly could not be lifted. Further attempts to remove the fuel assembly were delayed until the adjacent assembles were removed thus allaying concerns of potential interference from adjacent assemblies. The T-20 fuel assembly was bordered on two sides by the core shroud. A visual inspection on June 28, indicated that the fuel assembly appeared to have no clearance on one of the core shroud walls. Further attempts were made on June 28, 1989, to remove the assembly by increasing the bridge and trolley location deviation and allowable lifting force permitted by procedure FH-6. The assembly would not move.

The licensee solicited and Combustion Engineering provided written concurrence that the allowable lifting force on the fuel assembly could be increased in 400# increments up to 1600#. The assembly in question was to be a discharge assembly. On the afternoon of June 29, 1989, the Plant Onsite Safety Review Committee approved a change to FH-6 allowing the use of high lifting forces. Later that day, the fuel assembly was successfully removed with a lifting force of 400# over the assembly weight.

A subsequent inspection of the core support plate revealed the presence of what appeared to be a large portion of the shank of the missing bolt from 22B RCP. That piece was lying along the south face of the shroud, at the point where the interference had been observed prior to assembly removal. The bolt has been retrieved and is currently in a bucket in the refueling pool awaiting transfer to the spent fuel pool for inspection. The assembly has not yet been inspected further, but will be during the fuel inspection/repair campaign scheduled for August/September.

The inspector considered the licensee's performance throughout this event proper in that it reflected correct safety perspective. The inspector will review the results of the licensee's inspection of the stuck fuel assembly when completed.

7. Maintenance/Surveillance

7.1 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, fire protection, retest requirements, and reportability per Technical Specifications.

The following activities were included:

- Maintenance Order (MO) No. 209-181-222A, installation of temporary wide range nuclear instrument into the reactor core
- MO No. 209-049-937A, perform STP M-20 emergency diesel generator inspection
- MO No. 209-056-252, overhaul #21 EDG vertical drive assembly
- MO No. 208-326-835A, overhaul #21 EDG
- MO No. 209-144-467A, install plug-in-plug in Unit 2 steam generators
- MO No. 209-137-252, #11 pressurizer heaters, remove for sleeve and J-weld exams

The inspector had the following comments as a result of reviewing this program area.

- Between December 12, 1988 and January 20, 1989, the licensee conducted an internal maintenance team inspection. The objective of this inspection was to evaluate the maintenance process at the plant to determine whether timely and effective maintenance is performed, if appropriate management attention and involvement is evident, and if adequate resources are available to perform and support plant maintenance activities. The inspection followed NRC guidance and resulted in a report issued on January 31, 1989 by the licensee Quality Assurance and Staff Services Department. In response to weaknesses identified in the report, the licensee is evaluating contractor proposals that were submitted for the development of a maintenance improvement project. This multi-phase project will (1) review the areas that the licensee has identified as needing accelerated improvements; (2) develop a prioritized action plan; and (3) implement the maintenance improvement action plan. The NRC will continue to review licensee initiatives that are intended to address the need for improving licensee performance in the maintenance area.

- On June 12, 1989, the licensee announced the establishment of the position Superintendent - Nuclear Maintenance, who will report directly to the Manager - Calvert Cliffs Nuclear Power Plant Department. An individual with nuclear power plant experience from outside the licensee's organization was selected to fill the position.

- Defueling operations began on June 23, 1989, with two neutron detector channels as allowed by the Technical Specifications (3.9.2) during core alternations. Approximately two days before fuel movement began, a maintenance request was written on Channel "B" because it was indicating erratically. Instrument and Control personnel conducted an investigation, performed a functional test on the channel and declared it operable. One day prior to commencing defueling, an entry in the Nuclear Engineer Unit's log indicated that counts were increasing without fuel movement The inspector became aware of the problem with the neutron detectors during routine control room inspection on the morning of June 26, 1989. Nuclear Engineering Unit (NEU) personnel indicated that the problem was being closely monitored and parallel efforts were underway to install a temporary source range channel (dunker channel). On the evening of June 29, 1989, Channel "B" again exhibited erratic readings. Fuel movement was stopped shortly thereafter. The NEU recommended and the Plant Onsite Safety Review Committee approved increasing the counting interval on "B" Channel in order to improve the counting statistics. The inspector questioned the licensee as to whether the

problems with the neutron detector were related to neutron coupling or whether in fact there was a problem with the detector. The licensee conducted additional investigation, in spite of the fact that Channel "B" readings became less erratic. The instrument group conducted an extensive investigation and declared the channel operable. Operations conducted a surveillance test for the Reactor Protection System (RPS) and channel "B" did not pass. After recalibration and additional work on channel "B", operations reperformed the surveillance on the RPS and both channels passed on July 1, 1989. The licensee performed a safety evaluation consistent with 10 CFR 50.59 requirements to allow for the installation, use and removal of a temporary source range channel. During the aforementioned interval, the licensee installed the portable dunker detector in location A-8 which provided two channels which would remain operable until the end of defueling in the event channel "B" were to fail. At the end of the inspection period, defueling was proceeding uneventfully and 183 of 217 assemblies had been removed.

No unacceptable conditions were noted and the inspector had no further questions on this matter.

7.2 Surveillance

The inspector observed parts of tests or reviewed required documentation 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:

- Surveillance Test Procedure (STP) No. M-592-1, Penetration Fire Barrier Inspection
- STP No. 0-55A-2, Containment Integrity Verification (Mode 6)
- STP No. 0-61-2, Source Range Instrument Functional Test
- STP no. M-571-2, Local Leak Rate Test
- STP No. 0-73A-1, Engineered Safety Features Performance Test

Based upon reviewing the licensee's activities in the program area, the inspector had the following comments.

- By implementing the testing activity specified in procedure STP No. M-571-2, Local Leak Rate Test (LLRT), the licensee obtains as-found leakage data through the Type B and C containment penetrations of Unit 2. The reactor is in either Mode 5 or 6 during

the conduct of the tests. Technical Specifications (TS) Surveillance requirement 4.6.1.2.d specifies that Type B and C tests shall be conducted at intervals no greater than 24 months except for tests involving air locks, but the associated TS Limiting Condition for Operation (LCO) 3.6.1.2 is only applicable in Modes 1-4. However, Sections III.D.2(a) and III.D.3 of Appendix J to 10 CFR Part 50 requires a maximum retest interval of two years for Type B and C containment LLRTs, respectively.

Because of a shift from an 18-month to a 24 month operating cycle for Unit 2, the licensee requested the the NRC Office of Nuclear Reactor Regulation (NRC:NRR) issue a temporary schedular extension of 28 days beyond the maximum allowed 2-year test interval for performing each individual Type B and C containment LLRT on Unit 2. On March 15, 1989, the NRC issued an exemption from Appendix J of 10 CFR Part 50 and Amendment No. 118 to Facility Operating License No. DPR-59 for the one time 28 day extension for Types B and C containment LLRTs. During this inspection period, the inspector noted the existence of three deficiencies involving the licensee's failure to meet the requirements of 10 CFR 50, Appendix J on Unit 2.

(1) Penetration No. 41 consists of two motorized isolation valves (SI-652-MOV and SI-651-MOV) on the shutdown cooling line. TS LCO 3.9.8.1 governs shutdown cooling and coolant circulation in Mode 6, and specifies that the shutdown cooling pumps may be de-energized during the time intervals required for local leak rate testing of penetration number 41 pursuant to the requirements of TS 4.6.1.2.d. The prior Type C LLRTs conducted on the subject valves occurred on April 12, 1987. To be in compliance with the schedular extension, the test would have to be conducted by May 10, 1989. On May 4, 1989, the inspector was informed by the licensee that the performance of the LLRT was a concern from a prudency viewpoint. This was due to the licensee having only one of the two trains of spent fuel pool (SFP) cooling available, which they would rely upon to control the decay heat load while the shutdown cooling (SDC) system was inoperable for the conduct of the LLRT. On or about May 2, 1989, the #12 SFP pump had been declared out of service due to a cracked weld on it's discharge piping. On May 4, 1989, a licensee representative was in contact with the NRC:NRR project manager to discuss the condition. The licensee was informed that the condition did not appear to qualify under 10 CFR 50.91 for an emergency amendment. The inspector discussed the issue with NRC Region I management and it appeared that because the issue involved a potential exemption from 10 CFR Part 50, Appendix J, discretionary enforcement on a regional level might not be appropriate. This fact was communicated to the licensee.

The licensee appeared to be approaching this issue from a prudent safety perspective. The inspector requested that the licensee provide their analysis of what effect securing SDC with a full core would have. The licensee's Nuclear Engineering Unit analysis indicated that with the SFP cooling system's suction lined up to the refueling pool, a heatup rate of 2°F/hr. or less would occur with the SDC system secured. This indicated that it would take 38-40 hours to reach 200°F after securing SDC. The LLRT of the valves in penetration No. 41 was expected to be accomplished within an eight hour shift. The apparent difficulty that the licensing group representative was encountering in resolving this issue in a manner that would preclude the need to conduct the LLRT within the required time frame resulted in the operations and maintenance coordination group establishing May 6, 1989, as the scheduled test date. No further actions were requested of, or taken by, the licensing group on this matter.

As of May 7, 1989, the test was not conducted. The inspector discussed this issue with the Manager - CCNPP, and was informed that the test would be conducted prior to the exemption expiration date and no further assistance in seeking relief on this issue would be required of the NRC. On May 16, 1989, the inspector became aware that the penetration was not tested. Both the planning and scheduling efforts and management oversight were inadequate in assuring that the subject regulatory requirement was accomplished. Although the failure to conduct the test while the plant was in Mode 6 was of minimal safety significance, it does indicate a continuing trend in the licensee's inability to fully control and accomplish regulatory requirements. The failure to perform a Type C LLRT on the valves in penetration No. 41 by May 10, 1989 is one example of a violation of the maximum retest interval specified in Section III.D. of Appendix J to 10 CFR Part 50. (50-318/89-14-01)

(2) Penetration No. 38 consists of a single control valve (DW-5460-CB) on the demineralized water line. The Type C LLRT on this valve was last performed on April 27, 1987. The Appendix J, Section III.D.3 two year test requirements plus 28 day extension should have resulted in the licensee performing the required test by May 25, 1989. The test was subsequently performed on June 2, 1989. The reason for not

performing the test within the required time frame was attributed to excessive demineralized water makeup requirements to the service water head tank. The make up would have had to been isolated in order to perform the LLRT. Subsequent to the identification of the excessive make up condition, a leak was identified on the #22 service water heat exchanger. Corrective actions were initiated to allow the demineralized water to be secured and allow the conduct of the test.

The licensee's failure to insure the timely conduct of a LLRT on the demineralized water valve in penetration No. 38 is considered a second example of a violation of the maximum retest interval of a containment LLRT required by Section III.D of Appendix J to 10 CFR Part 50. (50-318/89-14-01)

On June 12, 1989, the principal engineer - licensing issued a Nonconformance Report (NCR) pertaining the failure to perform LLRTs on penetration Nos. 41 and 38 in accordance with the regulatory required testing frequencies. The response to the NCR (#8088) was assigned to the operations and maintenance coordination supervisor.

(3) Penetration No. 50 consists of a six inch pipe that has a blank flange and flexitallic gasket installed on both ends. A Type B LLRT is conducted by using an installed test valve located on the penetration outside containment. This penetration is used to pressurize containment as part of the performance of the integrated leak rate test that is performed on a periodic basis as well as providing service air inside containment. The operations and maintenance coordination group had scheduled the conduct of the Type B LLRT and subsequent removal of the blank flanges on March 27 and 28, 1989, respectively.

Prior to the start of the Unit 2 Refueling Outage on March 24, 1989, the licensee's maintenance planning organization issued Maintenance Order (MO) No. 208-336-016A to allow removal of the blind flanges and connect a portable air compressor to provide an air supply for the containment. According to the licensee, the planner knew that a LLRT was required to be performed prior to disassembly of the penetration's blind flanges, but failed to include this requirement in the MO. As indicated above, the licensee's scheduling reflected the necessary sequence to accomplish the task in a proper manner. Subsequently, on March 27, 1989, the MO package was implemented in a manner that resulted in the removal of the flanges on the penetration without the performance of a Type B LLRT per STP M-571-2.

On March 28, 1989, the cognizant systems engineer initiated NCR No. 7825 to document the occurrence of the event and initiate corrective actions. On June 7, 1989, the licensee issued voluntary LER 50-318/89-008 to describe this event. According to the LER, the planning schedule provided the proper sequencing of the activity, but neither the maintenance supervisor nor the tagging authority reviewed the planning schedule prior to authorizing the performance of the work.

Penetrations No. 50 was last tested on May 27, 1987 following it's reassembly near the end of the prior refueling outage. Prior LLRT data for this penetration conducted between 1982 and 1987 (seven tests) indicates a history of low leakage in the range of 15.3 to 250 sccm. Notwithstanding this fact, the inability to properly plan and control the conduct of an as-found LLRT on penetration No. 50 prior to its disassembly on March 27, 1989 resulted in a third example of a violation of the maximum retest interval of containment LLRTs required by Section III.D of Appendix J to 10 CFR Part 50. (50-318/89-14-01)

- In Section 6 of this report, a May 22, 1989 event was described that involved the discovery of a closed fire damper in the penetration ventilation exhaust system of Unit 2. On June 23, 1989, the licensee investigation of that event resulted in a determination that the once per 18 month TS Surveillance Requirement 4.7.12.a to conduct visual inspection of each required fire barrier penetration was not performed. This missed surveillance was STP-M-592-2, Penetration Fire Barrier Inspection. Immediately upon discovering the event, the shift supervisor was notified, and TS Action Station (AS) 3.7.12.a was entered at 11:00 a.m. This AS required within one hour, to either post a continuous fire watch, or verify the operability of fire detectors and establish an hourly fire watch patrol, or verify the operability of automatic sprinkler systems, as applicable. Because the AS represented activities of a very complex nature, the Limiting Condition for Operation could not be achieved until 2:00 p.m. the same day.

The licensee investigated the missed surveillance and determined that the Calvert Cliffs Inspection (CCI)-104, Rev. 1, Surveillance Test Program, had specified the TS 4.7.12.a required surveillance as having a frequency interval designated by the letter "R". Although this letter is not defined in the CCI, it was interpreted by the safety

and fire protection group, who are responsible for performing the surveillance, to mean every refueling outage. The last inspection occurred in May of 1987 and was due in November of 1988. Applying the 25% tolerance specified in TS 4.0.2.a would have allowed for conduct of the surveillance as late as April 1989. On the date it was discovered (June 23, 1989), the surveillance had not been performed, but was scheduled for the current Unit 2 refueling outage. As of the end of the inspection period, the inspector noted that the licensee was developing both short and long term corrective actions to address the root cause(s) of the missed surveillance. An LER (50-318/89-10) will be issued by the licensee to describe the occurrence and their intended corrective actions. The licensee's failure to adhere to the surveillance test requirement of TS 4.7.12.a remains an Unresolved Item pending the NRC's review of the subject LER. (50-318/89-14-02)

8. Calvert Cliffs Nuclear Power Plant (CCNPP) Units 1 and 2 ATWS Rule Implementation (10 CFR 50.62) (TI 2515/20)

8.1 Background

Paragraph (c)(1) of 10 CFR 50.62 specifies the ATWS mitigating system requirements for pressurized water reactors (PWRs). Equipment from the sensor output to the final actuation device that is diverse from the reactor trip system (RTS) is required to automatically initiate the auxiliary feedwater system and a turbine trip for the ATWS events. Additionally, paragraph (c)(2) of 10 CFR 50.62 requires that PWRs manufactured by Combustion Engineering must have a diverse scram system (DSS) "from the sensor output to interruption of power to the control rods".

The licensee's submittals for complying with the ATWS Rule received a safety evaluation and were accepted by NRC on November 2, 1988. The existing diverse auxiliary feedwater (DAFW) and the diverse turbine trip (DTT) designs were not modified because the DAFW and the DTT meet the requirements of 10 CFR 50.62. The new DSS, as discussed in the following paragraphs, is operational in Unit 1 and is being installed in Unit 2.

8.2 Scope

The inspector determined that the diverse scram system (DSS) was in compliance with 10 CFR 50.62 ATWS Rule. The inspector assessed the QA controls applied to the design, installation and testing of the DSS including ATWS equipment that is not safety related. Also assessed were the operational adequacy and reliability of the DSS.

8.3 CCNPP Diverse Scram System (DSS)

- System Description

The DSS is a backup system to the reactor trip system (RPS). The DSS will ensure a reactor trip on high pressurizer pressure if the reactor trip switchgear fails to operate. Diversity between the DSS and RPS begins with the sensor output and ends with the interruption of power to the control rods. The DSS is a four channel sensor system which provides inputs to two actuation channels. Each actuation channel opens one Control Element Drive Mechanism (CEDM) Motor - Generator load contactor resulting in a reactor trip.

The four sensor channels consist of pressurizer pressure sensors (PT102A, B, C D) and associated circuits. These sensors are shared with the RPS and ESFAS. The sensor channels, through isolators, provide pressure signals to four high bistables in the Engineered Safety Feature Actuation System (ESFAS) sensor cabinets. Each bistable provides channel trip annunciation and inputs to two additional isolators. One isolator provides input to a two-out-of-four logic module in channel "A" of the ESFAS cabinet while the other inputs to channel "B". The logic modules energize relays in each of the ESFAS relay cabinets to open the CEDM Motor - Generator load contactors. Both channels must actuate to initiate a reactor trip.

At power testing is provided through the use of a bypass contactor for the channel in test. The bypass contractor is in parallel with the load contactor and prevents the loss of output when the load contactor opens during test. The fact that the DSS is not available while the system is in bypass administrative control will limit the time that the system may remain in bypass.

Annunciation is provided on control room panel 1(2)C05 for both "DIVERSE SCRAM SYSTEM TRIP" and "DSS LOAD CONTACTOR BYPASSED".

- Review for Compliance to the ATWS Rule

The inspector noted the following relative to the implementation of the ATWS Rule by the Licensee:

- Licensee's plan for implementation of the ATWS Rule was revised and submitted on March 12, 1987, in accordance with NRC's letter of February 10, 1987, which allowed an extension no later than the third refueling outage after July 1984. Implementation for Unit 2 is on schedule for completion by the end of spring 1989.

- Engineering's Field Change Request (FCR) 85-1052 and its Control Work Packages (CWPs) 85-1052-E.2.I (Unit 1) and II (Unit 2) for the DSS effort were initiated by Calvert Cliffs Instructions (CCIs) 126H and 700A. Though the FCR is non-safetyrelated (NSR), this FCR was processed as a safety-related (SR) task because the ESFAS components used for the DSS function are SR components. The CWPs contained the engineering review/analysis, field engineering changes (FECs), installation procedures, and tests. The CWPs also contain material procurement data, maintenance orders, drawings, quality control (QC) coverage, the system turnover, affected documentation such as the FSAR, and the close out of the CWP in the case of Unit 1. The FCR and the CWP were followed and administratively controlled. FEC 85-1052-4, regarding the fabrication of connector pads for the Nos. 3 and 4 MG contactor load wiring, was questioned by QC and a non-conformance report NCR 7443 was written and the non-conformance was later resolved.

- Material procurement, receipt, and storage were reviewed and one high bistable (mech card No. 91094) was selected for follow-up in the records center, warehouse and Engineering Section's mech card file. The inspector found the procurement and mech card data to be complete, accessible and properly filed. Material location and care of the bistable in the warehouse was in accordance with Regulatory Guide (RG) 1.38.

- Diversity was evident during the verification of the RPS and DSS power supply relays. RPS relays were 8-inch K relays manufactured by Power Mate. DSS had 2-inch relays manufactured by Lamda.

- Equipment verified to be installed in accordance with CWP 85-1022-E.2.I to satisfy the ATWS Rule include:

    - Rewiring of relays K119 and K120 to terminal boards F9 and F7 respectively in accordance with paragraphs 5.8.2 and 5.9.2.

    - Replacement of spare low bistable with high bistable in Auxiliary Feedwater Actuating System (AFAS) panel 1C94 in Unit 1. The inspector noticed that the spare had not yet been replaced in Unit 2 AFAS panel 2C94.

- Installation of the Control Room alarm (annunciator) window in D18 at panel 1C05 and D19 in panel 2C05 in accordance with paragraph 5.10.1.

- Installation of the bypass contactor used to prevent the loss of output when the load contactor opens during test.

- Work on the DSS for neither unit was being performed during this inspection period. The inspector reviewed the following approved documentation to satisfy compliance with the ATWS Rule:

  - Operations preventive maintenance is performed by using the Operations Performance Evaluation (PE) Requirements. PE 1(2)-93-35-O-R requires an 18 month AFAS calibration of the sensors. PE 1-48-1-O-SA, for example, requires a DSS logic test be conducted semi-annually per Operations Instruction (OI)-34. Instructions for a future PE for the bypass contactor will be added to OI-42.

  - Surveillances conducted in accordance with surveillance test procedures (STPs) M-210A/B-1 (2), M-225-1 (2), and M-510-1 (2).

  - Preventive maintenance (PM) tasks conducted in accordance with PM procedures 1(2)-58-I-Q-1, 1(2)-58-E-R-2, 1(2)-58-E-R-3, 1(2)-48-I-R-4.

  - Engineering Test Procedure (ETP) 88-4, Section 6.2, Step 6.2.12 verifies that there are permanently installed means for bypassing the system during maintenance and testing with continuous indication of the bypass status in the control room. ETP also requires deliberate action to return to normal operation once the mitigating action is started and goes to completion.

  - ATWS mitigation system can by manually started from the control room in accordance with Emergency Operating Procedure (EOP)

- Initial and continued licensed operator training has been provided and is being assessed. Non-licensed training included actions to: brief the craft of the changes resulting from the ATWS Rule and add DSS in the continuing training course EM-59-2-0 for electricians. Changes to the ESFAS are being incorporated into the Reactor Coolant Pump course. These courses and the lesson plans reviewed by the inspector satisfactorily addressed the ATWS Rule changes. The training records of selected individuals were reviewed by the inspector. The records were complete, accessible, current and they indicate the individuals were trained and qualified.

- Included in the CWPs list of affected documentation was FSAR changes. A draft of the FSAR changes was reviewed by the inspector and the inspector found the changes to be adequately addressed.

Review indicates that the DSS activities were performed and documented in accordance with approved procedures by trained and qualified individuals.

8.4 Quality Assurance/Quality Control Interface

A Recommendation 88-18-R01 from the Quality Assurance (QA) Audit Report 88-18 was that an analysis be performed regarding the loss of power condition of the DSS caused by loss of a vital inverter or battery. Design's response to QA was to provide a copy of NRC's SER of November 2, 1988, which accepted the licensee's analysis of the same loss of power question.

QC inspectors involved in the DSS effort considered the CWPs to be good workable documents that the craft and QC inspectors could follow. The QC inspectors were knowledgeable of the CWP technical and administrative control requirements.

8.5 Conclusion

CCNPP Unit 1 DSS installation was completed on schedule and Unit 2 expects to have the DSS installation completed on schedule by late spring 1989. Design, procurement, installation and functional testing of the DSS met the requirements of 10 CFR 50.62 ATWS Rule and the licensee's commitments delineated in the NRC SER. The installation, QC surveillance, and testing were done by trained and qualified individuals. Documentation reviewed such as periodic surveillance and preventive maintenance procedures indicated that the Unit 1 DSS was operating satisfactorily prior to shutdown.

The licensee is expected to complete and functionally test the Unit 2 DSS on schedule. The licensee should be in compliance with 10 CFR 50.62 ATWS Rule when Units 1 and 2 return to service.

9. Licensee Event Reports (LERs)

LERs submitted to NRC:RI were reviewed to verify that the details were clearly reported, including accuracy of the description of cause and adequacy of corrective action. The inspector determined whether further information was required from the license, whether generic implications were indicated, and whether the event warranted on site follow up. The following LERs were reviewed.

9.1 Unit 1

LER No.	Event Date	Report Date	Subject
89-06	05/08/89	06/07/89	Containment Iodine Filters Outside Design Basis Due to Equipment Qualification
89-07	03/17/89	06/11/89	Damaged LPSI/Shutdown Cooling Suction Piping Restraint
89-08	05/08/89	06/07/89	Instrument Air Tubing to Salt Water Valves Found Outside the Design Basis, Caused by Poor Maintenance Practices
89-09 89-09, Rev. 1	05/19/89	06/19/89 06/21/89	Concerns Regarding Alternate Safe Shutdown Capability As Required by Appendix R

9.2 Unit 2

LER No.	Event Date	Report Date	Subject
89-07	05/05/89	06/02/89	Evidence of Leakage from Unit 2 Pressurizer Heater Penetrations Due to an Unknown Cause
89-08	03/27/89	06/07/89	Failure to Perform a Local Leak Rate Test

No unacceptable conditions were noted.

10. Review of License Response to NRC Initiatives

10.1 TI 2515/93 Diesel Generator Fuel Oil

In January 1980 through Multi-Plant Action (MPA) A-15, the NRC requested all licensees to verify that Emergency Diesel Generator Fuel Oil was included in their Quality Assurance (QA) programs or to justify its lack of inclusion. At Calvert Cliffs, all safety-related structures, systems, components and activities that are subject to the requirements of the QA Program are required to be included on the Quality List (Q-List). The inspector examined the facility's Q-List and verified that the fuel oil for the emergency diesel generators was included as a component on the Q-List. Therefore, activities associated with TI 2515/93 are considered complete.

10.2 TI 2515/94 PWR Boron Dilution Requirements

Multi-Plant Action (MPA) B-03, originally issued through DOR Information Memorandum No. 7 on October 4, 1977, identified a potential moderator dilution event that was not previously reviewed. In this scenario, while the reactor was in cold shutdown, a portion of the contents of the NaOH tank gravity drained into the Decay Heat Removal System during test cycling of the tank isolation valve. The NaOH was subsequently injected into the Reactor Coolant System. This NaOH injection would dilute the moderator and could result in reactor criticality. The BG&E evaluation of this event at Calvert Cliffs Unit 1 and 2 found that it was bounded by the boron dilution event analyzed in the Updated Final Safety Analysis Report. Consequently, the NRC letter of March 1, 1979, in agreeing with this finding, determined that no further action regarding MPA B-03 was necessary with respect to Calvert Cliffs Unit 1 and 2. Therefore, as no plant system or administrative control changes were necessitated at Calvert Cliffs for this moderator dilution incident, the inspector determined that the verification of these changes, as prescribed by TI 2515/94, is inapplicable to this facility and all actions associated with this TI are considered complete.

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 report information. The following periodic report was reviewed.

- May 1989 Operating Data Reports for Calvert Cliffs No. 1 Unit and Calvert Cliffs No. 2 Unit, dated June 9, 1989.

No unacceptable conditions were identified.

12. Events Requiring NRC 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 for root cause identification.

- At 5:39 p.m. on May 19, 1989, the NRC was notified in accordance with 10 CFR 50.72(b)(2)(ii) that the licensee had identified concerns involving their ability to implement the alternate safe shutdown procedure (AOP-9) for a control room evacuation in either Units 1 or 2. This issue is discussed further in Section 6 of this report.

- At 2:50 p.m. on May 22, 1989, the NRC was notified in accordance with 10 CFR 50.72(b)(2)(iii)(c) that the licensee discovered that the Unit 2 main duct fire damper for penetration room exhaust system was found closed due to failure of fusible links. This issue is discussed further in Section 6 of this report.

- At 2:00 p.m. on June 14, 1989, the NRC was notified in accordance with 10 CFR 50.72(b)(2)(i) that the licensee determined that the environmental parameters for the five foot east piping penetrations rooms in Units 1 and 2 used in the Environmental Qualification Program are incorrect. The licensee plans on issuing LER 50-317/89-010 to document this event and it will be reviewed by the NRC as part of LER followup activities.

- At 12:22 p.m. on June 30, 1989, the NRC was notified in accordance with 10 CFR 50.72(b)(2)(i) that the licensee had discovered that a fire damper in the spent fuel pool ventilation duct for the miscellaneous waste evaporator room was never installed in the duct. This event is discussed further in Section 6 of this report.

No unacceptable conditions were noted.

13. Visit of Delegation of the USSR State Committee for Supervision of Nuclear Power Safety (SCSNPS)

On May 17, 1989, an official delegation from the USSR SCSNPS visited the plant. Dignitaries included the Chairman of the SCSNPS. The visitation included: (1) a presentation by the NRC Region I Division of Reactor Projects Deputy Director on the NRC's Power Reactor Inspection Program; (2) the licensee's view of their relationship to the NRC; (3) the simulation of control room response to an emergency; (4) a plant tour; and (5) a tour of the Emergency Operating Facility. The inspectors attended all activities enumerated.

14. Unresolved Items (93702)

Unresolved items require more information to determine their acceptability and are discussed in Section 3 of this report.

15. Management Meetings (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.