U. S. NUCLEAR REGULATORY COMMISSION
Region I

Docket/Report: 50-317/85-15 License: DPR-53
50-318/85-13 DPR-69

Licensee: Baltimore Gas and Electric Company

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

Inspection At: Lusby, Maryland

Dates: June 18 - August 15, 1985

Inspectors: for T. C. Elsasser 9/9/85
T. Foley, Senior Resident Inspector Date

for T. C. Elsasser 9/9/85
D. C. Trimble, Resident Inspector Date

Approved by: T. C. Elsasser 9/9/85
T. C. Elsasser, Chief, Reactor Projects Section 3C Date

Summary: June 18-August 15, 1985: Inspection Report 50-317/85-15,50-318/85-13.

Areas Inspected: Routine resident inspection of the Control Room, accessible parts of plant structures, plant operations, radiation protection, physical security, fire protection, plant operating records, maintenance, surveillance, open items, Annual Emergency Medical Drill, documents provided to the licensee and reports to the NRC. Inspection hours totaled 238 hours. No violations were found.

Results: During the period the licensee demonstrated strong initiative and took conservative actions in identifying and correcting the root cause of recent failures of the #21 Main Steam Isolation Valve. Weaknesses were noted, however, in two other areas. First, corrosion/erosion problems in the suction bells of the Salt Water pumps and a repair technique being used to correct these problems did not appear to have been adequately evaluated by the licensee. Second, two Unit 1 plant trips occurred due to personnel error (valve in a secondary system not restored to proper position after removal of a system tagout and failure of operators to maintain proper steam generator level).

During the period the licensee identified a repeat problem associated with the separation of laminated sections of the armature of Reactor Trip Breaker undervoltage devices. The licensee plans to notify the vendor and industry of this problem. An NRC IE Notice on this subject is under review.

## DETAILS

1. Persons Contacted

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

2. Summary of Facility Activities

Unit 1 remained shutdown while repairs to the Main Electrical Generator lower stator bars insulation was being effected.

Unit 2 entered the period on its 26th day of full power operation since its last start up.

On June 24, 1985, Unit 1 was brought critical and commenced low power physics testing with the Main Generator decoupled from the turbine. Two days later the testing was complete, and the unit returned to cold shutdown to perform additional eddy current testing on the Steam Generators, replace No. 12B Reactor Coolant Pump Seal, and refurbish No. 12 Salt Water Pump.

On July 18, two pin hole sized steam leaks were identified on a cold reheat line just above the Unit 2 High Pressure Turbine. Because of this, the licensee shutdown Unit 2 on July 24 to examine and repair the steam pipe. During this shutdown Main Steam Isolation Valve 21 (MSIV 21) failed to fully close when required for surveillance test purposes. The licensee immediately embarked on a test program to determine the "root cause" of the failure. Repairs to the Cold Reheat line took about one day. Investigation of MSIV 21 continued for several days.

On July 30, after repairs to Unit 1 Main Generator were completed and while the unit was heating up to recommence operation, Reactor Coolant Pump (RCP) 11B experienced a failed seal. The unit returned to cold shutdown to replace the No. 11B RCP seal.

On August 5 both units were near operating temperature. Unit 2 had identified and corrected several problems with 21 MSIV, and Unit 1 had replaced the RCP seal. Unit 2 became critical at 6:23 a.m. and paralleled to the grid at 10:05 a.m.. Unit 1 became critical at 2:05 p.m. and after generator testing paralleled to the grid at 4:03 a.m. on August 6. At 4:27 on August 6, Unit 1 tripped from 17% power due to a high level in the Moisture Separator Reheator (MSR). At 1:50 p.m. Unit 1 returned to power operations. Later on August 6 Unit 1 tripped from 28% power at 9:46 p.m. due to a low Steam Generator water level condition. The unit was returned to power on August 7 at 5:47 a.m., however at 7:50 p.m. tripped on "loss of load" from 50% power. The unit again returned to power operations at 9:35 a.m. on August 8, and remained at power throughout the rest of this period. The above events are discussed in detail in the paragraph entitled Events Requiring Prompt Notification.

Four inspections were conducted by regional specialists in the following areas: Post Accident Sampling; Radiological Waste Transportation; a follow up team inspection of Post Accident Sampling and related TMI Action Plan items; and Environmental releases/monitoring.

Facility housekeeping and Control Room environment and professionalism remain consistently good.

3. Licensee Action on Previous Inspection Findings

(Closed) Inspector Follow Item (317/85-07-05) Need for Clarification of Pump Vibration Monitoring Procedure. The inspector reviewed Unit 2 Surveillance Test Procedure STP 0-73-2, ESFAS (Engineered Safety Features Actuation System) Equipment Performance Test, Revision 22, dated May 24, 1985 and confirmed that the procedure clearly specifies the vibration sensing instrument to be used and the sensing points on the pumps to be monitored. The inspector confirmed with the Surveillance Test Coordinator responsible for vibration monitoring that similar information was scheduled for inclusion in the Unit 1 STP. Incorporation of this information was expected by August 15, 1985. This item is closed.

(Closed) Violation (318/81-23-04) Technical Specification Instantaneous Radioactive Release Limit (for I-131 and Particulates with Half Lives Greater than 8 days) Exceeded. This problem resulted from apparent back leakage from the Volume Control Tank (VCT) through an in-line check valve to a nitrogen supply header relief valve (1-RV-105). This problem appears to have been an isolated event. VCT pressure is now administratively limited to a maximum of 50 psig (by operator log) and an annunciator alarm at this pressure provides warning to the operators of a high pressure condition. The inspector confirmed that the relief valve setpoint was checked during the Spring 1985 refueling outage. That valve setpoint is 70 psig. This 20 pound margin reduces the likelihood of similar releases in the event of check valve back leakage with appropriate allowance for relief valve setpoint/VCT pressure instrument drift. This item is closed.

(Closed) Unresolved Item (318/83-21-03) Installation of Improved Locking Devices on Locked Valves. The licensee replaced clipped chain locking devices with pad locked chains. This item is closed.

(Closed) Inspector Follow Item (317/83-18-02 and 318/83-21-01) Licensee Evaluation and Modifications to Ensure a Loss of Instrument Air Will Not Cause Unanticipated Failures of Safety Related Systems. As described in Section 2 in Inspection Report 50-317/84-03, 50-318/84-03, the licensee performed the above evaluation and found deficiencies in three ventilation systems. Facility changes have been completed on both units which resolve these deficiencies. Specifically, a second accumulator was added for motive air for the fan discharge dampers for the Emergency Core Cooling System Pump Room, Spent Fuel Pool, and Penetration Room Ventilation Systems. This item is closed.

(Closed) Unresolved Item (317/83-31-05) Licensee Unable to Comply with Environmental Technical Specification (ETS) 2.3.B.4 in that Automatic Release Isolation Based Upon Iodine and Long-Lived Particulate Activity Does Not Exist. This was due to an apparent error in the ETS's. The TMI Action Plan (II.F.1) acknowledges that on line monitoring (measurement) of iodine may not currently be possible with presently available equipment. On July 1, 1985 Technical Specification Amendments 105 (Unit 1) and 86 (Unit 2) were issued which deleted Appendix B (ETS) and incorporated new Radiological Effluent Technical Specifications (RETS) into Appendix A. RETS does not include a requirement for automatic release isolation based on iodine and particulates. This item is closed.

4. 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, and operating orders.

No violations were identified.

b. System Alignment Inspection

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

-- Containment Cooling, Units 1 and 2 checked on June 28, 1985.

-- Iodine Filters Inside Containment, Unit 1, checked on July 11, 1985.

-- Emergency Boration, Units 1 and 2 checked on July 25, 1985.

-- Auxiliary Feedwater System, Units 1 and 2 checked on August 12, 1985.*

-- High Pressure Safety Injection System, Units 1 and 2 checked on July 16, 1985.

*For this system, the following items were reviewed: The licensee's system lineup procedure(s); equipment conditions/items that might degrade system performance (hangers, supports, housekeeping, etc.); instrumentation lineup and operability; valve position/locking (where required) and position indication; and availability of valve operator power supply.

(1) On August 12 during a verification of system operability, the inspector noted that neither steam driven Auxiliary Feedwater pump 21 or 22 on Unit 2 were aligned for automatic initiation. The inspector verified that the No. 23 motor driven Auxiliary Feedwater pump was properly aligned and operable.

Investigation of status of the pumps revealed that 21 AFW pump (normally aligned for automatic initiation)was removed from service for preventative maintenance. No. 22 AFW pump is normally aligned in the "standby mode" with both steam supplies locked shut. Technical Specification 3.7.1.2 states:

"Two auxiliary feedwater trains consisting of one steam driven and one motor driven pump and associated flow paths capable of automatically initiating flow shall be OPERABLE. (An OPERABLE steam driven train shall consist of one pump aligned for automatic flow initiation and one pump aligned in standby.)* and

With one steam-driven pump inoperable:

(a) Align the OPERABLE steam driven pump to automatic initiating status within 72 hours or be in HOT SHUTDOWN within the next 12 hours, and

(b) Restore the inoperable steam driven pump to standby status (or automatic initiating status if the other steam driven pump is to be placed in standby) within the next 7 days or be in HOT SHUTDOWN within the next 12 hours.

With any two pumps inoperable:

1. Verify that the remaining pump is aligned to automatic initiating status within one hour, and

2. Verify within one hour that No. 13 motor driven pump is OPERABLE and valve 1-CV-4550 has been exercised within the last 30 days, and

3. Restore a second pump to automatic initiating status within 72 hours or be in HOT SHUTDOWN within the next 12 hours.

*A standby pump shall be available for operation but aligned so that automatic flow initiation is defeated upon AFAS actuation."

The 21 AFW pump had been removed from service in the morning on August 12 and was scheduled for approximately 24 hours of preventive maintenance. The Limiting Condition for Operation (LCO) stated above provides for 72 hours to align the standby pump for automatic initiation. Since the maintenance would be completed prior to the expiration of the LCO operators did not realign the "standby pump" for automatic initiation.

During discussions with the Plant Superintendent it was mutually agreed that the operating philosophy should be such that any time a component or system is out of service for any reason, and another is capable of performing the intended function of the component out of service, then it should be placed in service to minimize the time during which the margin to safety is reduced (allocated time of the LCO). The licensee immediately placed the standby pump in the automatic mode, which provided the original reliability and redundancy while performing maintenance on what now would be considered the "standby pump".

The licensee was requested to evaluate what other systems, (i.e., the "swing" HPSI pump) have standby components which could be used in lieu of the primary component to provide the original capabilities required by Technical Specifications rather than remaining in an Action Statement at a reduced margin to safety. The licensee stated they would evaluate the potential generic applicability on other systems.

(2) During this period an incident took place at the Davis-Besse Nuclear Power Plant which highlighted problems associated with operator access to vital areas. The inspector reviewed licensee procedures in this area and determined improvements were necessary to expedite access. This subject was discussed with the Plant Superintendent. Necessary procedure changes are planned to be made by August 12, 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.

No violations were identified.

d. Other Inspections

(1) Cause of Failure of #21 Atmospheric Dump Valve

Following a trip of Unit 2 on April 25, 1985 #21 Atmospheric Dump Valve failed open. The licensee determined the root cause to be mechanical interference of the positioner feedback linkage. The positioner was manufactured by Moore Products (Model #72G315). The remaining atmospheric dump valves were inspected. A similar potential for interference was found and corrected in one of the Unit 1 Atmospheric Dump valves. All problems were corrected.

This is the only safety related application for these positioners, however, the licensee will check other Moore positioners elsewhere in the plant by the end of the year.

(2) Review of Procedures for Mispositioned Control Element Assemblies (CEA's)

Because of industry problems associated with improper recovery of misaligned CEA's (which could potentially damage fuel cladding), the inspector reviewed procedures in this area. Those procedures did adequately define steps necessary for a recovery from a mispositioned CEA. The inspector did note, however, a potentially confusing arrangement of steps in Abnormal Operating Procedure AOP1B, Revision 20, dated May 3, 1985. In Section II of that procedure, "Mispositioned CEA's (greater than 15 inches misaligned)", Step B.5 directs that if a CEA has been misaligned and a power reduction was not commenced in less than one hour of the misalignment, then operators should not attempt to recover the CEA without first seeking the guidance of the Fuel Management Group (a shutdown to comply with Technical Specifications is an allowed exception). The potential confusion arises in that Step B.5 follows a step directing realignment of mispositoned rods that does not contain the precautions of B.5. An operator could, therefore, first realign a CEA and then realize his proper action should have been to first contact the Fuel Management Group for guidance. The licensee agreed that this was confusing and will appropriately modify the procedures. No unacceptable conditions were identified.

(3) Salt Water Pump Suction Bell Erosion/Corrosion

During the period, operations personnel discovered through wall leakage on the suction bell of the #12 Salt Water (SW) pump. The pump was removed from service and disassembled. During mechanical cleaning three additional holes were identified. The holes were finger sized and spaced around the periphery of the suction bell (near the top flange). Although general erosion/corrosion damage was evident on the surface area near the flange, the licensee determined that any significant wall thinning problems were confined to the localized areas of the holes. The holes and thinned walled areas were repaired with a metal filler material ("Belzona") and the surface was coated with coal tar epoxy.

Less severe damage of the same nature had previously been found and similarly repaired by the licensee on SW pump #21. A through wall hole on the #11 SW pump, due to erosion, was previously found and repaired.

In 1984 the casing of the #22 pump was found to be near minimum wall thickness and is currently being monitored for further degradation (casing scheduled to be replaced at next Unit 2 refueling outage - Fall 1985).

The inspectors discussed this general problem with the Plant Superintendent (PS) who stated that remaining Unit 2 SW pump suction bells will be inspected during the fall refueling outage and that the remaining Unit 1 pump will be inspected before that outage. The PS also stated an evaluation will be conducted regarding the potential for and consequences of further suction bell failures (including failures of Belzona material). This item will be followed by the NRC (IFI 317/85-15-01). The licensee's engineering group previously performed a safety analysis for the Belzona repairs of the suction bells (Facility Change Request 84-12). However, that analysis appeared inadequate in that it did not address the potential for and consequences of failure of the Belzona plugs nor did it address the potential and consequences of failure of the as yet uninspected pumps (which history would indicate suffer similar degradation problems).

(4) <u>Limited Review of ECCS Systems Subject to Potential Overpressurization Due To A Intersystem Loss of Coolant Accident (LOCA)</u>

The inspector reviewed all Emergency Core Cooling Systems (ECCS) connecting to the Reactor Coolant System and containing components or piping with design pressures equal to or less than 70% of the RCS design pressure. The purpose of this review was to confirm information in NUREG/CR-2069, Summary Report on a Survey of Light Water Reactor Safety Systems. No discrepancies were identified.

A sampling review of the testing of valves in-line between high and low design pressure systems was done. Following is a summary of that testing.

| Component | Test Description/Plant Condition |
|---|---|
| Shutdown Cooling Suction Motor Operated Valves (MOV's) | Cycled each refueling to verify automatic closure at 300 psig RCS pressure. Also received Local Leak Rate Test (LLRT). |
| HPSI/LPSI Check Valves | Forward Direction, full flow test once per refueling, (Surveillance Test Procedure STP 0-66), plant in Cold Shutdown. |
| LPSI Check Valve SI-114, HPSI Check Valve SI-113 | Quarterly reverse flow (STP 0-65), plant operating. |
| HPSI/LPSI Shared Check Valve SI-118 | Reverse Flow tested at refueling, Cold Shutdown (STP 0-66). |

| | |
|---|---|
| HPSI/LPSI Shared Check Valve SI-217 | No test conducted, however, a downstream control room alarm annunciator and indication exist (alarm at 300 psig). |
| HPSI/LPSI MOV's | Timed Cycle Test quarterly (STP 0-65), cycled monthly with automatic ESF actuation system (STP 0-7), cycled once per refueling as part of integrated ESF TEST (STP 0-4). Valve stroke times trended. |

Through discussions with maintenance and operations personnel, the inspector learned that very few MOV problems have been experienced. The surveillance coordinator could not recall any significant problems with check valve back leakage. Two shift supervisors recalled, however, one isolated instance in the 1978 time frame when one HPSI leg was pressurized to full RCS pressure up to the normally closed MOV due to check valve back leakage.

Plant maintenance is not performed on the check valves. Every other refueling planned maintenance is conducted on MOV controllers, limit switches, torque switches, and insulation.

No unacceptable conditions were identified by the inspector during this review.

5. 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.

-- During this period three plant trips occurred during the startup on Unit 1. For each trip the licensee notified the NRC Duty Officer and all automatic reactor protection features responded as designed.

On August 6, 1985, at about 4:30 a.m. while increasing power the unit automatically tripped from 17% power. The annunciator indicated a turbine trip, which caused an automatic reactor trip. The turbine trip was caused by a high level in the Moisture Separator Reheater (MSR). This was due to a mispositioned isolation valve which was erroneously aligned after a tagout was cleared on the MSR. This reactor trip was due to a breakdown in the tagout control system and could have been prevented.

At approximately 2:00 p.m. the unit returned to power operation. While escalating in power at 28% the unit tripped again. This trip was due to low steam generator water level which directly trips the reactor protection system. The cause of the low water level was failure of the reactor operators to adequately control water level and coordinate the reactor power and feed the steam generators. The inspector noted that this is an unusual condition for the operators since the reactor is at the beginning of core life and has positive temperature coefficient at this time, which requires a substantial change in operation by the operators during startup. This was discussed with the General Supervisor, Operations who stated that the onsite simulator would be programmed appropriately and the Training Department would be requested to incorporate these concerns in their program before the next startup from refueling.

This trip was due to operator error, perhaps insufficient training, and could have been prevented.

The third trip occurred at approximately 8:00 p.m. on August 7, 1985 due to a "Loss of Load" caused by the turbine thrust bearing wear detector. The trust bearing detector was apparently misaligned. The licensee's vendor normally makes this adjustment. This is not considered to be a trip that could have reasonably been prevented. The unit returned to power operation in the morning of August 8 and remained at power through the rest of the period.

No violations were identified.

6. Observations of Physical Security

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

No violations were identified.

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

LER's submitted to NRC:RI were reviewed to verify that the details were clearly reported, including accuracy of the description of cause and adequacy of corrective action. The inspector determined whether further information was required from the licensee, whether generic implications were indicated, and whether the event warranted onsite followup. The following LER's were reviewed.

| LER No. | Event Date | Report Date | Subject |
|---|---|---|---|
| Unit 2 | | | |
| 85-02 | 05/06/85 | 06/05/85 | Reactor Trip caused by an Inadvertent Actuation of 21A RCP Overcurrent Device |
| 85-03 | 05/18/85 | 06/17/85 | Incorrect Fastener Material Used in Pressurizer Spray Valves |
| 85-05 | 05/23/85 | 06/21/85 | Recirculation Actuation Signal Inadvertent Initiation |
| 85-06 | 05/26/85 | 06/21/85 | Inoperable Diesel Generators |

8. Plant Maintenance

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

-- Purge of #21 MSIV Hydraulic Package observed on July 30, 1985.

-- Refurbishing of #12 Salt Water Pump.

Reactor Trip Breaker UV Device

During routine maintenance on July 24, 1985 on Unit 1 Reactor Trip Circuit Breaker (TCB) #5, technicians noted that pickup and dropout voltages for the undervoltage (UV) device were below their minimum allowable values (pickup 101.1 volts vice specified minimum of 104 volts; drop out voltage 37.5 volts vice specified minimum of 36.3 volts). The laminated armature to pole piece gap was found to be below its minimum allowed value of .029 inches (actual .022 inches). The licensee determined that the laminated sections of the armature, which are riveted together, were loose on their rivet such that relative movement between sections was occurring. A similar, but more severe, problem was noted on Unit 2 TCB-1 in February 1985 (see section 10 of Inspection Report 50-317/85-02, 50-318/85-02) which caused excessive breaker trip response times. In the present case, TCB-5 on Unit 1, response time was not noticeably affected. The UV device on TCB-5 was replaced and the problem thereby corrected. The licensee plans to notify the vendor (GE) of the problem and to advise other utilities (via "Network") of this problem. It should be noted that the licensee checks the armature to pole piece gap based upon a recommendation from a vendor representative. Pertinent service advice letters do not mention this check. Since other utilities may not be taking this measurement and since it may provide a valuable warning of subject lamination separation problem, the licensee will discuss this measurement in their industry notification.

No violations were identified.

9. Surveillance Testing

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

-- M220-1, ESFAS Functional Test, observed on July 10, 1985.

-- 0-1-2, MSIV Fast Stroke Test, observed on July 26 and 30, 1985.

-- On July 10, 1985, while observing the performance of Surveillance Test Procedure STP M220-1, ESFAS Functional Test, the inspector noted that the terminal label plate was missing for the A2 terminal block in Sensor Cabinet ZE. The technician in charge stated that he would mention this fact to his supervisor and initiate a maintenance request for a replacement plate.

No violations were identified.

10. Licensee Response to Generic Letter 83-28, Generic Implications of ATWS Events at the Salem Nuclear Power Plant

The NRC's Region I office is assisting the Office of Nuclear Reactor Regulation in reviewing the licensee's response to selected items of Generic Letter 83-28.

The licensee's February 29, 1984 response to Item 3.2.1 described their review to assure that post maintenance testing of all safety related equipment was being performed. This review adequately addressed the item and was scheduled to be completed by January 31, 1985.

The inspector reviewed a sample of the documentation completed by the licensee for close out of their review. Through discussions with the licensee on July 18, 1985, the inspector determined that Item 3.2.1 had been properly closed by the licensee as a result of their completed review.

11. Annual Emergency Medical Drill

On August 7, 1985 the licensee conducted the Annual Emergency Medical Drill. The inspector witnessed various parts of the drill and discussed aspects of the drill with Mr. F. Rocco of Helgeson Scientific Services, consultant to the licensee.

The drill consisted of two injured personnel, one seriously injured and contaminated. The second individual required only first aid and local decontamination procedures. Both persons were located on the 45 foot elevation of the Auxiliary Building by the Steam Generator Blowdown tank when the injuries were sustained. First aid was administered promptly and appeared effective. Ambulance response was not hurried, nor was it untimely.

Calvert Memorial Hospital fully participated providing a very real simulation. Doctors and nurses worked well with Health Physics technicians decontaminating the injured man. Hospital procedures are in place and appear effective in handling radiological medical emergencies. The hospital facility and staff appear to be adequately supported with appropriate radiological supplies and detection instrumentation.

The inspector had no unresolved concerns regarding the medical drill.

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.

13. Main Steam Isolation Valve Operability

The Plant Final Safety Analysis Report and Technical Specifications require that the Main Steam Isolation Valves (MSIVs) be tested by part stroking during operation and full stroke test per article IWV-3000 of Section XI of the American Society of Mechanical Engineers (ASME) Code (FSAR Section 10.1.2.2 and TS 3.7.1.5). ASME Section XI IWV-3400 also requires that power operated valves be time tested. The licensee has been timing this part strokes of the MSIVs on a weekly basis. During the preceding several months the licensee has been puzzled by erratic stroke times (34 to 190 seconds) apparently changing without cause on 21 MSIV. The other MSIVs have been consistently 50 +/- 20 seconds. Because of this a decision was made to full stroke/fast stroke the valve during the next available shutdown.

On July 24, 1985, while shutting down Unit 2 to repair a pinhole steam leak on a cold reheat steam line, the licensee manually initiated an MSIV closure of 21 MSIV in accordance with STP-O-1 "Main Steam Isolation Valve Test". During this test the valve failed to fully close, and failed to meet the TS requirements to close within 3.6 seconds. The valve was subsequently closed utilizing an installed hydraulic pump. The licensee embarked on a test program to determine the cause of the failure.

Based on previous problems and subsequent test program described in Inspection Report 50-317/85-01 dated February 25, 1985, and current pressure data on cap end and rod ends (of the hydraulic actuator),the licensee determined that either air or nitrogen was entrapped in the hydraulic fluid or a gas bubble existed in the system thereby preventing the valve from being fully functional. Gas in the system would either displace fluid causing insufficient volume to close the valve or provide a gas volume to absorb the hydraulic force/pressure to shut the valve.

The licensee's program consisted of an operational evaluation during both fast and slow strokes of the valve. The following were performed before, during, and after the operational evaluation, as appropriate:

-- System flushes of hydraulic fluid and replacement of hydraulic fluid.

-- Checks of accumulator and surge suppressor bladders for gas leaks.

-- Analysis of hydraulic fluid for total gas concentration and identification of specific gas in solution.

-- Comparison checks between 21 MSIV and other MSIV hydraulic packages.

-- Attachment of visicorder test equipment to monitor instantaneous pressure parameters.

-- A simulated hydraulic accumulator failed bladder test to reproduce the failure mechanism.

-- Overhaul of the hydraulic oil pumps and check for air leakage.

-- Isolation of individual accumulators to determine reserve capacity.

-- Replacement of surge suppressors.

-- Refurbishment of hydraulic check valves.

Several strokes of the valve shortly after shutdown and after flushing the system appeared to indicate the valve was operable, (i.e., met the 3.6 second criteria of Technical Specifications) however, cap end pressures were not as per the technical manual (2400 psi vice minimum of 2600 psi after each stroke). Test data appeared to reflect some time dependency associated with acceptable strokes of the valve in that: If a stroke was acceptable and then a period of 6-8 hours passed, the next subsequent stroke generally failed.

After many unsuccessful and some successful strokes with indication that the "Gas problem" still existed, the licensee determined that a Gas Surge suppressors bladder had failed (was leaking only during valve operation). The surge suppressor maintained 1200 psi and would drop to 1100 psi after cycling the MSIV. This was corrected and several sequential strokes passed the acceptance criteria established by the licensee of 3.6 seconds overall stroke time (TS 3.7.1.5); 2600 psi cap end pressure after the stroke (FSAR) and less than .2 seconds valve response time after initiation.

The valve was then declared operable and heat up to normal operating temperature was performed 6-8 hours after the previous tests. This hot stroke failed to meet each of the acceptable criteria. An investigation revealed three failed accumulator bladders that appeared to leak only during valve functioning but otherwise would maintain between 3000 and 5000 psi. The bladders were replaced, hydraulic check valves refurbished and the valve tested.

The valve passed two sequencial tests and was also part stroked. All parameters returned to approximately those of the other MSIV's and also met all established acceptance criteria. The determination of the root cause failure of MSIV 21 was pin hole leaks in high pressure hydraulic accumulators and surge suppressor bladders. This involved approximately 35 strokes of the valve and seven days of testing. The licensee stated that as a result of this problem, the bladder leak detection (PM) procedure would be revised and performed weekly vice monthly, STP-0-47 MSIV part stroke test would be revised to monitor reservoir level during strokes as an indication of system voiding, STP-0-1 MSIV Fast Stroke would be revised to verify bladder integrity before and following fast stroke testing, and operator logs would be revised to record MSIV reservoir levels once per shift to detect bladder failures. Additionally, "alert" and "action required" ranges would be established for the part stroke test by which the valve may be declared inoperable during operation should it exceed the action requirement limit.

This licensee performance is in consonance with the NRC's policy on determining the root cause of equipment failures prior to declaring a component operable. No inadequacies were identified.

14. Diesel Generator Interpolar Connecting Bars

Section 4d of Inspection Report 50-317/85-13,50-318/85-11 discussed failures in and removal of diesel generator interpolar connecting bars.

Two region based NRC inspectors visited the plant site and the licensee's metallurgical lab, examined the Diesel Generators, and held discussions with plant personnel. The above report describes the fact that additional cracks in connecting bar stubs left in two generators were identified by one of these inspectors. Those stubs were subsequently removed. Additionally, those inspectors arrived at the following conclusions.

The inspector concluded that the BG&E Metallurgical Group had adequately investigated and reported the failure cause and had recommended appropriate corrective action.

As the site did not initially remove the connecting straps at the position that would also remove shorting strap fatigue cracks, a lack of communication between the Metallurgical Lab and the site was noted. The BG&E QA/QC organization is evaluating this occurrence to identify and correct this apparent communication problem.

The inspector reviewed the licensee's engineering evaluation, Facility Change Request (FCR) No. 85-1025, dated May 26, 1985, on the change of the emergency diesel generators' output caused by removing the interpolar connecting straps which link the damper bars on the faces of the field poles. The FCR is based on information supplied by the manufacturer as evaluated by the BG&E electrical engineering department.

The inspector reviewed this evaluation and concurred with the licensee, after subsequent discussions with the manufacturer/vendor (Louis Allis), that by removing the copper connecting straps, the generators' output will have no measurable affect on voltage and frequency regulation nor will any relay coordination have to be recalculated.

Based on this review, the inspector concluded that the removal of these straps will change the negative sequence reactance and the subtransient reactance by increasing them. The net effect will be reduced fault current. The connecting straps will have a measurable effect only when the generator is run in parallel with a unit of dissimilar size. Parallel operation of emergency diesel generators is in violation of Techncial Specification requirements.

Subsequent to the removal of the connecting straps, the inspector reviewed the Emergency Diesel Generator Surveillance Test Procedures (STP-O-4-1) for #12 and #21 generators to verify conformance with previous testing results. In addition, the inspector reviewed the vibration analysis performed and concluded that voltage regulation currents, frequency, and vibration results were in conformance with prescribed procedures.

Based upon their followup of this event during the week of June 10, 1985, the region based inspectors concluded that the BG&E company had provided for evaluation of effects of removal of the interpolar connecting straps and provided for removal of the straps including the fatigue cracks in the shorting strap stubs. Based on a review of operating history of 14 similar diesels without the interpolar connectors, a review of specific factors involving this issue, and input from the manufacturer and independent observations, the inspectors concluded that satisfactory preventive/corrective actions have been completed or were in progress.

No violations were identified.

15. 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:

-- April, 1985 Operations Status Reports for Calvert Cliffs No. 1 Unit and Calvert Cliffs No. 2 Unit, dated May 14, 1985.

-- May, 1985 Operations Status Reports for Calvert Cliffs No. 1 Unit and Calvert Cliffs No. 2 Unit, dated June 17, 1985.

-- June, 1985 Operating Data Reports for Calvert Cliffs No. 1 Unit and Calvert Cliffs No. 2 Unit, dated July 11, 1985.

-- During this period a memorandum dated April 12, 1985 to J. Taylor, Director IE from W. Dircks, Executive Director for Operations regarding Housekeeping and Control Room Behavior at Nuclear Power Plants was provided to the Plant Superintendent. This memo is believed to be in the Public Document Room.

16. 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.