U. S. NUCLEAR REGULATORY COMMISSION

Region I

Docket/Report: 50-317/85-28 License: DPR-53
50-318/85-28 DPR-69

Licensee: Baltimore Gas and Electric Company

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

Inspection At: Lusby, Maryland

Dates: October 1, 1985 - November 4, 1985

for T. C. Elsasser
T. Foley, Senior Resident Inspector — 11/27/85 date

for T. C. Elsasser
D. C. Trimble, Resident Inspector — 11/27/85 date

Approved:

T. C. Elsasser
T. C. Elsasser, Chief
Reactor Projects Section 3C — 11/27/85 date

Summary: October 1 - November 4, 1985 Inspection Report 50-317/85-28, 50-318/85-28.

Areas Inspected: Routine resident inspection of the Control Room, accessible parts of plant structures, plant operations, events reported to the NRC, physical security, Licensee Event Reports, maintenance, surveillance, refueling activities, TMI Action Plan Items, radiological effluent, post accident effluent monitoring, Emergency Operating Procedures, SFP cooling, Hydrogen Recombiners, organizational changes and Measuring and Test Equipment program.

Inspection Hours totalled 237 hours.

Results:
Although no violations were found, significant concerns were identified regarding the testing of Steam Generator Safety Valves (Section 11). The inspection included a review of previous corrective action regarding failures of safety valves and determined that appropriate corrective action had been initiated at the time.

Results of the licensee's corrective action for the current, repetitive and more significant failures remain unresolved pending completion of a planned corrective action program and demonstration of adequate assurance of valve operability.

Additional concerns were identified regarding the potential for bypassing administrative controls (Section 5) when using the discretion afforded in CCI-200I (permitting exceptions in the use of a detailed maintenance procedures) and CCI-117 (reduced prior review of jumpers installed and removed in the same shift). Permitting this discretion resulted in the loss of a vital cooling system, discussed under reports to the NRC.

These are areas where the licensee may denote additional attention.

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: On October 1, the unit returned to power operation following a plant trip due to an undetermined electrical problem, associated with the feedwater heater level circuit. On October 3, the unit tripped again apparently due to the same previously unidentified problem. This time, the cause was identified to be due to electrical grounds on the 11 DC Bus and grounds within the feedwater heater level control circuit. The grounds were corrected and the unit returned to power. On October 9, RCS unidentified leakage increased from .5 gpm to .8 gpm. An investigation identified a cracked control bleed off line weld on 11A RCP. The licensee commenced an orderly shut down and declared an Unusual Event due to a plant shut down required by Technical Specification for a leak which now had increased to approximately 1 gpm. The plant was cooled down and drained to repair the cracked weld. Flanges from all four RCP control bleed off lines were replaced with a light weight coupling. On October 13, during the fill of the RCS, after repair of the RCP lines, a valve which had not been properly shut leaked and caused approximately 500 gallons of water from the Refueling water Tank to drip out of the Containment spray header spray rings, wetting several primary system components. On October 15 Unit 1 returned to service and remained at power operation throughout the period.

Unit 2: Routine operation characterized performance until October 19 when the plant shut down to commence its sixth refueling outage. The expected duration of the outage is 47 days, and includes the following major activities:

-- Refuel the reactor
-- Overhaul actuator on 21 Main Steam Isolation Valve
-- Replace 21A and 21B Reactor Coolant Pump Seals
-- Eddy current examination of 21 and 22 steam generators
-- Replace channel heads on saltwater heat exchangers
-- Alignment and vibration checks of Reactor Coolant Pumps
-- Containment Integrated Leak Rate Test
-- Refueling machine modifications
-- Replace 21B Reactor Coolant Pump motor
-- Reactor vessel water level system pressure boundary modification
-- Inspect and overhaul 21 emergency diesel generator.

On day 17 of the Unit 2 outage the critical path progressed to approximately 3 days ahead of schedule. To date, this refueling outage has been characterized by strict adherence to planned activities and good

communication between licensee and contractor work groups and plant staff. Unit 2 is now expected to return to service on December 1, 1985.

3. Licensee Action on Previous Inspection Findings

(Closed) Unresolved Item (317/83-16-02) Loss of Pressurizer Level Indication During Cable Meggering Check. Because a procedure for insulation resistance testing did not clearly identify cables to be tested a contract electrician disconnected an operational cable for meggering. He did not first check to see if the cable was energized. For corrective action the licensee added a note to insulation resistance test procedures to remind construction personnel to verify that conductors are de-energized before disturbing them and changed the Control Work Package Procedure (CCI-700A dated May 1, 1984, paragraph 7e) to require cables to be tested to be clearly identified in the test procedure and require that these tests be controlled by the Nuclear Power Department. This item is closed.

(Closed) Violation (318/81-23-03) Technical Specification Instantaneous Radioactive Release Limit Exceeded. The item was closed in Section 3 of Inspection Report 317/85-15;318/85-13 but incorrectly labeled as item No. 318/81-23-04. See below for closure of item 318/81-23-04.

(Closed) Unresolved Item (318/81-23-04) Adequacy of Installed Instrumentation to Monitor High Level Releases. The licensee has installed, in response to TMI Action Plan Item II.F.1 a Wide Range Noble Gas Monitoring system for each unit. That system is currently operable on Unit 2. The Unit 1 system has been installed and is undergoing final checkout before being declared operable. This item is closed.

(Closed) Unresolved Item (318/83-02-06) Pressurizer Spray Valves Drifting Open Following Loss of Instrument Air Due to Containment Isolation Signal (CIS)). These valves should be held closed upon loss of instrument air by spring pressure assisted by local air accumulator pressure. During the current Unit 2 refueling outage the licensee will verify that the valves will remain closed upon isolation of instrument air. Additionally, Facility Change Request FCR 83-60 will be implemented during the outage which will allow Instrument Air Isolation valve 2CV-2085 to be reopened from outside Containment to restore air to the spray valves. Previously, once closed 2CV-2085 could only be opened from inside Containment. 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, tagout logs, and operating

orders. At various times during the period, inspectors attended Plant Operations Safety Review Committee meetings to ascertain TS minimum requirements and make an independent assessment of the effectiveness of the committee's activity. Routine trends in stimulating questioning are generally apparent.

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

-- Unit 2 Shutdown Cooling checked on October 24, 1985.

-- Unit 2 Hydrogen Recombiners Inside Containment checked on October 28, 1985.

-- Unit 2 Containment Air Coolers checked on October 28, 1985.

-- Unit 2 HPSI/LPSI/SIT Inside Containment checked on October 28, 1985.

No violations were identified.

c. Biweekly and Other Inspections

During plant tours, the inspector observed shift turnovers; boric acid tank samples and tank levels were compared to the Technical Specifications; and the use of radiation work permits and Health Physics procedures were reviewed. Area radiation and air monitor use and operational status was reviewed. Plant housekeeping and cleanliness were evaluated. Verification of the following tagout indicated the action was properly conducted.

-- Tagout #15040, #21 Diesel Generator checked on October 29, 1985.

No violations were identified.

5. Events Requiring Notification To The NRC

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

-- On October 2, 1985 at 12:10 p.m. Unit 1 experienced a reactor/turbine trip due to an erroneous feedwater heater high level signal. This was identical to the trip experienced two days earlier which the root cause could not be identified. Portable instrumentation installed after the initial trip enabled the licensee to positively identify the cause of this trip as grounds on the equipment powered by the 11 DC Bus which resulted in energization of the feedwater heater trip relay. The grounds on both all DC Buses were corrected and on the feedwater heater level circuit, and power operation resumed on October 3.

-- On October 13, 1985 the repair of the Reactor Coolant Pump (RCP) Control Bleed Off Lines weld crack was completed. Conditions for the repair required the reactor water level be drained below the weld repair area. During the fill of the Reactor Coolant System (RCS) in accordance with OI-1D Reactor Coolant System Fill and Vent, Control Room Operators (CROs) noted an increase in frequency of the draining of the reactor cavity sump. A CRO stationed inside the Containment to vent the system during the fill of the RCS investigated and found no apparent cause for the increased leakage. A change in shift personnel occurred and as required the plant was pressurized to 200 psi. Simultaneously another operator was sent to continue the investigation of the sump frequency increase. This operator noted water dripping from about one-third of one of the Containment Spray rings. The Control Room was notified and a reverification of the valve line up was initiated which resulted in closing valve SI-329 (12 shutdown cooling Heat Exchanger outlet to Containment Spray) an additional two turns, using additional mechanical leverage to fully shut the valve.

Clean up and electrical checks of wetted components followed during the subsequent four hours.

An investigation of this incident revealed that valve SI-329 was operated once during OI-3 placing the plant on shutdown cooling when the normally open valve was shut, then again during the performance of STP-0-66-1 Quarterly Valve Operability Verification which checks valve SI-329 shut. Interviews of those operating/checking the valve indicated that both had operated the valve from a reach rod, designed to minimize the radiation dose to operators in the event of an accident. The valve, a ten inch velan disk valve with a Tulsa Roto Hammer Operator attached to a reach rod, is difficult to operate even when performed locally. Both operators used the position indication on the reach rod, without placing additional torque on the valve in order to check the valve shut.

Discussions with the shift personnel indicated that no plant policy exists regarding use of reach rods for normal plant operations involving valve manipulation. Calvert Cliffs Instruction CCI-300, Section VII requires that when checking a valve, that an attempt to move the valve in the shut direction shall be performed in conjunction with

local valve position indication. Both operators apparently performed this on the reach rod.

During a discussion with the General Supervisor-Operations the licensee stated that the above CCI-300 would be re-emphasized and a policy would be promulgated to operators requiring the use of the local valve operator vice reach rod for all valve manipulations except those requiring use of reach rods due to inaccessibility due to location or high radiation levels.

Issuance of such a policy should prevent future occurrences of this nature. The issuance of this policy will be followed by the NRC (317/85-28-01).

-- At 11:26 a.m. on November 1, shutdown cooling flow was lost on Unit 2 when one of the Reactor Coolant System (RCS) hot leg suction valves (MOV 651) closed. The Control Room Operator noted the annunciation of the decay heat pump (Low Pressure Safety Injection Pump) low suction pressure alarm and secured the running pump. Unit 2 was in Mode 6 at the time. The refueling cavity was flooded, and refueling was in progress. Refueling operations were immediately suspended. The MOV closure was caused by technician error while replacing a relay associated with controller 2- PIC-103. By design MOV 651 shuts if RCS pressure, as sensed by pressure transmitter 2PT-103 (associated with 2PIC-103), exceeds approximately 300 psig. This protects the shutdown cooling system from over-pressurization. Shutdown cooling was quickly restored at 11:34 a.m.

The inspector discussed the event with the lead technician involved, the technician's supervisors, and a QC supervisor. The relay was being replaced with an improved device as part of a facility change. The actual work was being done under a maintenance order. The technician was being assisted by a second technician who normally works at another licensee facility but had been temporarily assigned to this plant for the outage, and a QC inspector was monitoring the job. The relay replacement was essentially a six step process. The first step was to install a terminal board jumper which would maintain the control circuit to MOV 651 energized. The last step should have been to remove that jumper. The licensee's Modification and Support Group had previously decided that the relay replacement was within the knowledge and skills of the technician and, therefore, the maintenance order did not include specific procedural steps. The facility change package had been reviewed by the POSRC and included a precaution about this relay replacement. However, that precaution was not carried over into the maintenance order. The same technician had performed this relay change without a problem on Unit 1 during its last refueling outage. At an intermediate point during the relay change out process, the lead technician told the temporarily assigned technician to complete the job while he began preparations to replace another relay. The second technician removed the jumper in the wrong step sequence, which resulted in MOV closure. The lead technician apparently had not provided sufficient guidance to his assistant.

Although the technician's immediate supervisors felt this evolution was within the knowledge and skills of the employee, the group's General Supervisor, who has had more experience with this circuit, told the inspector that this circuit is complicated enough that he feels it warrants a step by step procedure. However, he was not involved in the decision to work without a procedure. Calvert Cliffs Instruction CCI-200I, dated April 1, 1985, Step III.H, permits the supervisor to make a determination regarding whether or not a detailed procedure is required based upon whether the work is within the skills normally possessed by maintenance personnel.

The inspector noted that the jumper was not installed in accordance with Calvert Cliffs Instruction CCI-117E, "Temporary Mechanical Device, Electrical Jumper and Lifted Wire Control". The licensee pointed out that that procedure does not apply if installation of the jumper is performed under a maintenance order and the individual performing the work removes the jumper during the same work period. The maintenance order must document installation and removal of the device. Therefore, CCI-117 did not apply.

The inspector discussed this event with the Plant Superintendent and pointed out the following:

a. When detailed procedures are not included in maintenance orders (MO), QC effectiveness is reduced in that (by procedure) MO's are not routed to QC for review for problems/hold points prior to the work and during the work they have no standard or criteria to check the work against. This potentially valuable review is lost. Without detailed procedures, supervisor review of maintenance orders is less effective in spotting problems. Similarly POSRC review is not required when detailed procedures are not included.

b. One of the purposes for CCI-117 is to adequately review the effects of jumpers, etc. before they are added to a system. The exclusion of work that can be accomplished in one shift does not appear to meet the overall intent of the procedure unless the details of that work receive a sufficient review through another mechanism (e.g. detailed MO).

c. In combination, the option of omitting detailed procedures in maintenance orders and the exclusion of certain jumper installations from CCI-117 requirements, could potentially lead to abuse and allow work to be accomplished on safety related systems without adequate reviews for possible effects and procedural problems.

The Plant Superintendent stated he would further evaluate these problems. Licensee action to improve controls in this area will be followed by the NRC (IFI 318/85-28-03).

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 (LERs)

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

LER No.	Event Date	Report Date	Subject
Unit 1			
85-11	09/30/85	10/29/85	Main Turbine Trip Due To an Undetermined Cause
85-12	10/02/85	10/31/85	Main Turbine Trip Due to a Grounded Feedwater Heater Level Control Switch
85-13	10/09/85	11/05/85	RCP Shaft Seal Bleedoff Line Weld Failure

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.

-- Unit 2 Main Steam Isolation Valve Actuator observed on October 25, 1985.

-- MO #205-248-233A Replace Turbocharger of #21 Diesel Generator observed on October 29, 1985.

-- Rigging of new channel head for #22 SRW Heat Exchanger observed on October 29, 1985.

-- Main Steam Safety Valves observed on November 6-7, 1985.

-- MO-205-10-010C Replacement of Butterfly Valve 2-SW-5155.

-- Inspection of the No. 21 Emergency Diesel Generator, STP-M-11-2.

-- Inspection, Disassembly and Reassembly of 12" Atwood Morrill Safety Inspection Tank Check Valves per MO-8402407.

Emergency Diesel Generator Maintenance

On October 30, 1985 surveillance testing being performed on the No. 21 diesel engine was observed. This surveillance, performed using STP-M-20-0, Revision 11 is a thorough inspection of all major diesel engine components including a lube oil analysis. A quality control inspector and a Colt Industries diesel inspector were present during the performance of STP. Both inspectors were actively involved with the inspection and knowledgeable of the required surveillance. The diesel engine technical manual was used frequently to ensure compliance with the manufacturers recommendations. Work area access was properly controlled.

Alignment verification was made of selected piping systems on the No. 11 and No. 12 diesel generators ensuring Technical Specification 3.8.1.1 was satisfied. The following systems' lineups were verified for both diesel generator No. 11 and No. 12:

-- Air start piping
-- Fuel oil piping
-- Lube oil piping
-- Service water piping.

No inadequacies were identified. However, general cleanliness in diesel generator rooms No. 11 and No. 12 were noted to be below the general standards maintained throughout the rest of the plant. In particular, loose rags were found under the No. 12 diesel engine. Additionally, both engines have oil on their casings in various locations beyond what would be expected for satisfactory cleanliness. These conditions present an unnecessary potential fire hazard and were discussed with the licensee. These will be monitored during the routine inspection program.

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:

-- STP M-571-2, Local Leak Rate Testing of Penetration 61 observed on October 24, 1985.

-- STP 2-SIT-10Y-1, Hydrostatic Testing of Safety Injection Tanks observed on October 24, 1985.

-- STP M-20-0, #21 Diesel Generator observed on October 29, 1985.

-- STP-M-571, Local Leak Rate Test of SI-340.

Steam Generator Snubber Surveillance

On October 28, 1985, the licensee informed the NRC that 2 steam generator snubbers on Unit 2 failed to meet their acceptance criteria during a functional test. TS 4.7.8.1c requires a functional test of at least 10% of snubbers in plant use at least once per 18 months during shutdown. Snubber No. 2-63-19 failed its functional test for both lock up velocity and bleed rate. Snubber No. 2-63-11 failed for lock up velocity. The licensee stated that a Combustion Engineering review of the failures determined that the acceptance criteria for lock up velocity was conservative. Combustion Engineering has provided the licensee with revised acceptance criteria which brings both snubbers within acceptable limits for the lock up velocity criteria.

The failure of Snubber No. 2-63-19 to meet the bleed rate criteria requires, in accordance with TS 4.7.8.1c, that an additional 5% of the snubbers be functionally tested until no more failures are found or until all snubbers have been functionally tested. Calvert Cliffs' TSs do not specify however whether 5% of all plant snubbers need to be tested or 5% of the same type of snubbers (mechanical/hydraulic or a large bore or small bore) that failed the functional test.

Discussions between the resident inspector, the licensing project manager, and regional specialist resulted in the determination that the snubber type (large or small bore) distinction was erroneously omitted from the Calvert Cliffs TS, that the intent of the TS is to provide additional confidence in the area of technical concern i.e., large bore snubbers. Standard TSs include the type distinction and therefore it was determined that only 5% of the steam generator snubbers (large bore) need be tested to satisfy TS 4.7.8.1c. The licensee plans to submit an amendment change to clearly designate snubber type in their TSs and thereby prevent any ambiguity in future interpretations of this TS.

The licensee functionally tested steam generator snubber No. 2-63-20 to meet the 5% test requirement. This snubber passed under the revised Combustion Engineering lock up velocity criteria and the existing bleed rate criteria. In addition, although not required by TSs, the licensee tested an additional steam generator snubber to ensure confidence that the installed snubbers are performing their intended safety related function. This snubber, No. 2-63-20, also met the revised lock up velocity criteria and the existing bleed rate criteria.

During the above investigation, the inspector also reviewed Surveillance Procedure STP M-11-2, Revision 14 which provides the guidelines for identifying, removing, testing, calibrating, accepting, and installing a

representative sample of at least 10% of the safety related snubbers as required by TS 4.7.8.1. A representative sample is required to include those listed in Table 3.7-4 as "especially difficult to remove" or "in high radiation zones". A review of Attachment A of STP M-11-2, Revision 14 revealed that the sample chosen for the current Unit 2 refueling met the intent of Technical Specifications. Further review of STP M-11-2 revealed that an adequate engineering analysis was performed for the failed steam generator snubber as required by TS 4.7.8.1c.

No violations were identified.

10. Unit 2 Refueling Outage

On October 19, Unit 2 performed an orderly shutdown to commence its sixth refueling outage. The planning effort and control of the project has been very well conducted. Outage goals were as follows:

-- 47 scheduled days duration
-- Less than 250 person-rem exposure
-- Maximize use of ALARA concepts
-- Complete all priority A and B maintenance
-- Complete all outage modifications

Eight major work paths were identified consisting of 2,100 activities and 110,000 planned man hours of work. Each work path identified the major activities, prioritized work, set milestones, identified potential problems, and identified shift work schedule for each area.

An independent effort regarding ALARA has, as of the middle of the outage, shown a very significant improvement over previous outages, as follows:

-- Shielding the Refueling Pool 44' floor resulted in a 50% decrease of exposure compared to last outage.

-- Due to review by the ALARA group, changes were made to primary side steam generator work (i.e., Nozzel Dam and Eddy Current equipment installation and removal). This required more mock up training, additional on the job supervision and stressing group cooperation. This resulted in a reduction of from 42 man-rem installation of equipment last outage to 7 man-rem for installation of equipment this outage.

-- Changes were made in the methodology of shielding the Regenerative Heat Exchanger.

-- More briefings to contractor health physics technicians and group supervisors regarding their role in ALARA.

-- More cooperation between ALARA Coordinators, dosimetry and unit supervisors, resulting in lowering the maximum dose to individuals.

These efforts have resulted to date in a total outage exposure of 71 man rem of a scheduled 250 goal. Last outage's total was 276 man-rem.

Outage communications and supporting activities appear to be a significant contributor to the thus far success of this outage. General planning, information, and status meetings are conducted each morning followed by technical problems and coordination meetings immediately thereafter. Daily general maintenance meetings are conducted for the coordination of work for the operating unit. Plant Operations Safety Review Committee meetings are held three times a week and prospective managers meetings for the restructured organization occur weekly. Meetings attended by the resident inspectors have been conducted in an orderly, succinct manner.

The outage control staff has clearly defined responsibilities of the various work groups, and with the Plant Superintendent's endorsement holds groups accountable for work progress. This has resulted in the critical path being 80 hours ahead of schedule on day <u>19</u> of the <u>47</u> day outage.

To date the inspectors observed various aspects of the following major activities in progress. Most activities are yet to be completed.

- Refueling of the reactor and associated activities
- Overhaul of 21 MSIV actuator
- Replacement of service water heater exchanger channel heads
- Reactor vessel water level monitoring system modification
- 21 Emergency Diesel Generator overhaul
- Ultrasonic testing of secondary and primary system piping
- Inservice inspection hydrostatic pressure tests of safety injection tanks
- Addition of human factors up grades and engineering enhancements to the control boards
- Upgrading various electrical switches and connections to environmentally qualified models
- Reviewed safety analysis for relocating air supply line for CV-2035
- Removal of Incore Instruments (ICI) wires
- Attended briefing for "jumpers" installing Nozzel Dams in steam generators
- Removal and testing of steam generator snubbers
- Inservice inspection of salt water system piping at circulating water system
- Inservice inspection of salt water system piping at service water system
- Local leak rate testing of various valves inside Containment

During inspection of the activities associated with disassembly of salt water system and components, the inspector independently examined the condition of the surfaces of components and piping exposed to the salt water environment.

The area surrounding the volute and impeller of the 21 circulating water pump appeared in very good condition, with little marine growth (due to

velocity of flow around the pump). Marine growth did significantly increase as the inspection progressed toward the condenser in the circulating water piping. However, the growth was not more than what might be expected, i.e., 2-3 inches in length. Engineers designated various points to be inspected and where marine growth should be removed for examination and possible refurbishment (i.e., re-cement/mortar the lining). The piping in the area of the Service Water Heat Exchanger (SWHX) appeared clean with little marine growth; no evidence of significant corrosion. Several cast iron butterfly valves are installed in this piping. One valve, 2-SW-5155 was observed during its removal for replacement. The valve was being replaced because the Surveillance Test Procedure STP-0-65 results exceeded the acceptance criteria for closing time. The valve condition appeared to have minor pitting and only slight corrosion. General condition of the area is good.

The inspectors plan to view the salt water portions of the Component Cooling Heat Exchanger (CCHX) when they become available. This is a low flow area where more significant corrosion and marine growth is expected. Currently, the licensee continues to examine salt water systems, salt water pumps, and are in the progress of completing installation of the new rubber lined channel heads for the SWHX and CCHX.

As previously identified in Inspection Report 317/85-13;318/85-15 the inspectors maintain a concern regarding the licensee's safety analysis failure to address the use of Belzona and coal tar epoxy on/in safety related systems, and failure to address the seismicity aspects of the degraded salt water pumps.

No violations were identified.

11. Review of Main Steam Line Safety Valves

During the Unit 2 shutdown/cooldown for the current refueling outage (shutdown began on October 18, 1985), the lift setpoints of the main steam safety valves (MSSV) were checked in accordance with Surveillance Test Procedure STP M-3-2, Revision 6 dated November 7, 1984. The data from this surveillance is listed in Attachment 1. The valves are manufactured by Dresser Consolidated, type 3700 valves, and are checked by hydroset with Reactor Coolant temperature between 495 and 515 degrees Fahrenheit. Eleven of the sixteen valves were found to have lift values outside the range allowed by Technical Specification (TS) 3.7.1.1 (TS lift setting +/- 1%). Those setpoints which exceeded the +/- 1% limit had drifts ranging from 22 to 71 psi.

Similar problems with setpoint drifts were experienced during the Spring 1985 Unit 1 refueling outage and during the previous Unit 2 refueling outage (e.g. 13 Unit 2 valves had to be adjusted). In the Spring of this year the licensee received NRC approval for a TS revision providing a wider range of allowable lift settings for the MSSVs. The same TS revision was requested and is currently under review by the NRC for Unit 2. In addition to the widened lift setting band for each valve, the new TS also states that settings are acceptable if, for each steam line, any two

valves lift between 935 and 995 psig, two other valves lift between 935 and 1035 psig and the four remaining valves lift between 935 and 1065 psig.

Several actual lift values obtained this Unit 2 outage fell outside the allowable range of the new TS. Specifically, eight valves were outside their individual limits. On one header no valves lifted in either the low or mid lift ranges described above. On the second header, only one valve lifted in the low range.

Historically, the licensee had some less severe drift problems with those valves in the 1977/1978 time frame. They worked with the vendor and established a practice of checking lift settings immediately before an outage at elevated RCS/steam generator temperatures. The problem disappeared and very good results were obtained until the Spring of 1984. After significant drift problems began to occur in 1984, the licensee discussed the problem with the vendor, reviewed their work practices, reduced the overhaul frequency on each valve from five years to three years, revised the surveillance test to require checking all sixteen valves each outage, and ordered new hydrosets. Currently, they are re-looking at failure data, calling in a vendor technical representative, and having the hydroset's calibration checked.

The licensee also plans to send off two of the valves with high drift problems to Wiley Laboratories. Tests will be conducted to determine (1) if ambient room temperature can affect lift setpoints, (2) if testing at RCS/steam generator temperatures and pressures somewhat below normal operating conditions can affect setpoint, and (3) how long it takes for valve component temperatures to steady out after a plant heatup/cooldown. Both valves will have their setpoints set with a common hydroset (new) and the valves will be "pop" tested to verify setpoint. The valves will be returned, installed and rechecked using the same hydroset as used at the test facility. All other valves will then be checked with the same hydroset.

The inspectors will continue to monitor licensee progress in resolving the MSSV setpoint drift problem (IFI 318/85-28-02).

At the beginning of the outage the inspector checked five MSSVs and found the cap/drop lever assemblies to be loose on four of those valves. The lock screws securing the assemblies to the valve yoke were missing on two valves and were loose on the other two valves. If these assemblies are loose, it may be possible during a valve lift for these assemblies to vibrate and cock in such a manner as to contact the release nut (on the spindle) and prevent valve closure. The inspector pointed this out to the licensee. They informed the inspector that they will examine methods of improving the locking device and improve STP M-3-2 to add a step at the end of the procedure to tighten the locking screw (currently only a general step exists stating to "reassemble the valve which was disassembled in Step 3", therefore the lock screw could be overlooked).

The inspector also compared STP M-3-2 with the valve technical manual (Dresser Maxiflow Safety Valve Manual 3700) regarding setpoint testing and adjustment. Only one disparity existed. The procedure stated to increase hydroset pressure until the valve begins to simmer audibly. The technical manual states: "increase the hydraulic pressure to the hydroset to obtain a lifting force that causes the valve to just barely "spit" or simmer. This pressure can readily be determined because of a slight downward deflection of the pointer on the hydraulic pressure gauge installed on the pump of the hydroset". The inspector was concerned that the audible threshold may vary with individuals and background noise, leading to error in setpoint determination. The licensee stated that the audible simmer and gauge pointer deflection occur simultaneously. However, they also had noted this disparity and had already planned to change the procedure to agree with the technical manual.

12. Licensee Action on NUREG 0660, NRC Action Plan Developed as a Result of the TMI-2 Accident.

The NRC's Region I Office has inspection responsibility for selected action plan items. These items have been broken down into numbered descriptions (enclosure 1 to NUREG 0737, Clarification of TMI Action Plan Items). Licensee letters containing commitments to the NRC were used as the basis for acceptability, along with NRC clarification letters and inspector judgment. The following item was reviewed.

-- II K.3.25 Reactor Coolant Pump (RCP) Seal Integrity Following Loss of Offsite Power. This item was previously addressed in Inspection Report 317/82-16 and report 317/85-24, 318/85-20.

In a Safety Evaluation issued by NRR on October 7, 1985, the staff determined that operator action to reinstate seal cooling is acceptable and therefore Calvert Cliffs Units 1 and 2 complied with the requirements of TMI Action Plan II.K.3.25. This item is closed.

13. Review of Radiological Effluent

On October 22, 1985 the inspector performed a sampling review to verify licensee compliance with recently issued (July 1985) Radiological Effluent Technical Specifications (RETS). The inspector reviewed Technical Specification (TS) requirements for dose and dose rate for gaseous effluents (TS's 3.11.1.1, 3.11.1.1, and 3.11.2.3) and the principle implementing procedure (RCP-1-604, Gaseous Waste Releases). He then reviewed related records and discussed aspects of the program with the engineer responsible for implementation of RETS, a Rad-Chem technician, and the Chemistry Supervisor. RCP 1-604 was the last procedure to be modified to include RETS requirements (Revision 9 approved October 4, 1985). Since that revision licensee personnel have noted several problems with the procedure and a subsequent change is planned. Those problems included: needed steps to calculate maximum allowable Wide Range Noble Gas monitor response in micro CI/CC and missing portion of procedure for calculating final activity release for Containment purges.

The inspector reviewed Gaseous Waste Release Permit (GWRP) P-94-85, modified Unit 2 Containment Purge conducted on October 20, 1985, and noted that the maximum allowed Main Vent Noble Gas monitor (RI-5415) response was calculated to be 2135 cpm. This value should represent 150% of the expected detector response based upon the activity in the gaseous release. During the release, the detector only registered a count rate between 60-75 cpm.

With no releases in progress, RI-5415 on Unit 2 shows a count rate of about 70 cpm. The Shift Supervisor on watch during the Containment purge described above stated he had noted that the Unit 2 Wide Range Noble Gas monitor was indicating an activity increase but RI-5415 was not responding. He contacted chemistry and had them compute the maximum allowed Wide Range Noble Gas monitor response to assure release limits were not being exceeded. The Shift Supervisor, however, did not initiate a Maintenance Request (MR) on the detector at that time. He informed chemistry and assumed they would initiate corrective action. The inspector noted that Unit 2 RI-5415 demonstrated a similar low response on October 11, 1985 (Waste Gas Decay Tank Permit W-90-85, maximum allowed count rate = 1670 cpm, actual count rate = 100 cpm).

Chemistry personnel although knowledgeable of a discrepancy between expected and actual detector response had not initiated a MR. The inspector expressed concern to the Chemistry Supervisor and the Shift Supervisor that RI-5415 was not responding properly and recommended an MR be submitted. That evening a source check and instrument drawer calibration check were done on the detector. These checks revealed no problems. The inspector then discussed the problem with the Plant Superintendent (PS) and recommended that RI-5415 readings be considered suspect until further checks could be run to confirm operability. The PS agreed that a problem did seem apparent and stated he would have it further investigated. The inspector also expressed concern regarding why the licensee personnel had not initiated a request for maintenance until he urged this action.

Licensee action to further evaluate the operability of Unit 2 RI-5415, perform corrective maintenance (if necessary) and sensitize personnel to recognize/initiate corrective action for radiation monitor response anomolies will be followed by the NRC (318/85-28-01).

14. <u>NRC Contractor Review of Post Accident Effluent Monitoring</u>

On October 8, 1985, the licensee's post-accident monitoring system, installed pursuant to the requirements of NUREG 0737, Item II.F.1-2, "Sampling and Analysis of Plant Effluents", was reviewed by a specialist from Bettelle Laboratories accompanied by an NRC inspector. Such review was for the purpose of comprehending problems associated with representative sampling of effluent release paths in accident conditions. The review included examination of the system design, the evaluation of operating data and the determination of operational parameters that could effect representative sampling. It is expected that the data and information

acquired in this review will assist the NRC in the development of generic guidance in this area.

The licensee representatives assisting in this review were cooperative and helpful in understanding system design and performance capabilities. No unsatisfactory conditions were noted.

15. Organizational Changes

On September 20, 1985, the Board of Directors of Baltimore Gas and Electric Company announced plans to restructure the utility to include a separate Nuclear Energy Division. Functional responsibilities will become effective January 1, 1986. The Nuclear Energy Division will consist of a Vice President and four major departments. The Plant Superintendent's position has been deleted, however, each department will now consist of an onsite Manager and a Vice President located primarily onsite. Major changes are as follows:

-- Mr. Joseph Tiernan, Manager-Nuclear Power was reassigned as of October 1, 1985 as Vice President, Engineering and Construction until January 1, 1986 when he will become Vice President of the newly created Nuclear Energy Division.

-- Mr. Walter Lippold replaced Mr. Tiernan as Manager-Nuclear Power until January 1, 1986 when he will become Manager, Nuclear Engineering Services.

-- Mr. Leon B. Russell currently Plant Superintendent will become Manager, Nuclear Maintenance Department.

-- Mr. James R. Lemons will become Manager, Nuclear Operations Department.

-- Mr. Robert Douglass will be Manager, Quality Assurance and Staff Services Department. (The name of the department will be changed from Quality Assurance to reflect moving quality control to the operating departments and bringing additional divisional support functions in with the quality assurance function.)

Reassignments for General Supervisors and Supervisors for each department were announced on October 24, 1985. A review of qualifications for those individuals whose reassigned positions are addressed in ANSI 18.1 1971 "Selection and Training of Nuclear Power Plant Personnel", to which the licensee is committed to in the Quality Assurance Manual, was performed. The position of Operations Manager as addressed in ANSI 18.1 section 4.2.2 requires that a Senior Reactor Operation's License beheld by the individual occupying the position. Currently, the proposed Manager of Nuclear Operations Department does not maintain a Senior Reactor Operators position. This is unresolved (317/85-28-02) pending revision to Licensee's

Quality Assurance program which should describe the newly created managers positions such that a comparison can be made to the ANSI requirements.

Another concern regarding the restructuring of the organization involves the Plant Operations and Safety Review Committee's (POSRC) membership.

The restructuring removes many years of plant experience and several key members who have demonstrated good conservative judgment combined with a clear understanding of the significance of potential safety issues. Removing the Plant Superintendent position, replacing the General Supervisor Training and Technical Services, and replacing in the recent past the General Supervisor, Operations, appears to have significantly reduced the experience level of the POSRC and in fact, totally eliminated the key figures who have in the past been the most dynamic and significant contributors to the safe operation of the facility. Removing these members in a radical manner will remove much of the plant knowledge currently available to support a sound approach to resolution of technical issues, devitalize an already over-burdened POSRC, and cause a process to occur in which old issues may be resurrected, both operationally and from a regulatory view.

The inspectors discussed this with the Plant Superintendent and requested that the licensee consider maintaining as many of the principal contributors as possible for as long as possible. The restructuring may provide many positive effects, however, the core of POSRC is being significantly reduced.

The effectiveness of the POSRC was addressed in the previous SALP report and will be carefully monitored by the inspectors in the future.

16. 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 10CFR 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.

17. Review of New Emergency Operating Procedures (EOPS)

During the period the inspector reviewed two new EOP's (EOP 200 Loss of Offsite Power/Natural Circulation and EOP 600 Steam Generator Tube Rupture) which will go into effect on January 1, 1986. Operators are currently receiving simulator training on the EOP's. Following a recent Reactor Coolant System (RCS) Natural Circulation (NC) test at a B&W designed plant, Steam Generator (SG) pressure rapidly increased and a SG safety valve lifted when reactor coolant pumps were restarted. Neither EOP 200 or 600 contain any precautions to warn operators of this type of problem. The inspector informed the licensee of the potential for this SG pressure increase, and the licensee decided to see if their plant would

react in a similar fashion by running a test scenario on the simulator. The simulator showed that SG pressure would indeed increase.

With RCS temperature in the range of 520 degrees Fahrenheit, during a recovery from two loop NC, SG pressure could exceed the lowest allowable SG safety valve setpoint (935 psig). During a recovery from single loop NC, SG pressure almost certainly would exceed the lowest relief valve setting. The licensee plans to further investigate this possibility, train operators on the problem, and (as appropriate) revise procedures.

The inspector noted that recovery action E of EOP 600, Steam Generator Tube Rupture (SGTR), directs that a subcooling margin of 25-35 degrees Fahrenheit be maintained. Recovery Action M says to isolate the affected SG when hot leg temperature (T_H) is less than 520 degrees Fahrenheit. If SG isolation is attempted at T_H about 520 degrees Fahrenheit and a subcooling margin of 35 degrees Fahrenheit the inspector determined that RCS pressure would be 1090 psia. The isolation action could then result in a SG pressure of 1090 psia, which is well above the setpoints for the SG safety valves. Safety valve opening would be counter to the objective of the procedure which is to isolate and contain the leakage. The inspector discussed this with the General Supervisor, Operations, the individual responsible for generating and correcting the EOP's, and the Operations Training Supervisor. Further investigation for possible procedure changes will be conducted.

The inspector also pointed out to the individual responsible for the EOPs that Recovery Action O of EOP 600, regarding cooldown/depressurization of the RCS with the affected SG isolated, directs the operator to maintain 25-35 degrees Fahrenheit subcooling margin in the unaffected SG but is silent about maintenance of subcooling margin in the affected SG. Neglect of that margin, in NC cooldown, could potentially lead to bubble formation inside the tubes of the affected SG and aggravate cooldown control problems. The individual responsible for the procedures stated he would also investigate this item. Licensee action on the possible procedure problems noted above will be followed by the NRC (317/85-28-03).

The inspector observed portions of an operator simulator training session. The simulator is an excellent facility. The instructor was capable and very professional. The participating operators maintained a serious attitude toward their training.

The concept and form of the new EOP appears very good. The operators appear to be receptive to the new procedures. Operator involvement in the development of the EOP's has been maintained and the idea of testing the procedures out on the simulator and accomplishing training at the same is excellent.

18. Review of Spent Fuel Pool Cooling

Although not required for safe shutdown, the Spent Fuel Pool Cooling system (SFPCS) was reviewed because of its importance to safety, in that it

provides shielding, cooling, and subcritical Boron concentrations for refueling and long term storage of spent fuel. The following areas associated with the SFPCS were examined in order to assess overall system capability: housekeeping, operating procedures, control room indications, surveillance, and maintenance.

System documentation was reviewed to assure adequacy in terms of training, operational, and regulatory needs. The system description, "Spent Fuel Pool and Spent Fuel Pool Cooling and Purification Systems", System Description No. 10, July 1983 provided a clean, concise description of the system design and operation. The FSAR also presents an accurate system description. The FSAR system drawing (M-58), in Figure 907, contains several errors and omissions: the refueling pool No. 11 discharge point is not shown as are the No. 11 and No. 12 spent fuel pool discharge spargers, and several alarm locations are not shown. The errors in drawing M-58 also appear in Operations Drawing (OM)-58. The licensee was informed of the errors and agreed to correct these errors.

Plant housekeeping related to the SFPCS was observed in the following areas: the 69 foot level spent fuel pools, the 27 foot level SFPCS room, and the 45 foot level refueling water tank (RWT) rooms. The Spent Fuel Pool Demineralizer and Filter Room was inaccessible due to the normally high radiation levels. The equipment, piping, supports and general surrounding areas of the SFPCS appeared to be clean and well kept, with a notable absence of tools and extraneous material, except in those areas where specific activities were in progress. The inside of electrical cabinets 52-1411 (motor control center for No,. 11 SFPC pump) and 52-2411 (motor control center for No. 21 SFPC pumps) were relatively free of dust, combustible or other adverse conditions.

The operating procedures for the SFPCS contained in OI-24 Revision 17, provides a clear description of a considerable number of functions associated with spent fuel and refueling pool cooling, filtration and RWT recirculation. Each function is clearly described including initial conditions, procedure for obtaining the desired system function, and returning to initial conditions. The attachment to OI-24 contains the system valve line up. An independent verification of valve position was performed by the inspector. The following inadequacies were noted: the location of SF P-237, given in the procedure as "above SFP", was actually found on the 45 foot level of the Auxiliary Building, west side; the identification on valves SFP-5 through SFP-14 do not agree with that provided in OI-24. While the incorrect procedure location of the low point drain valve SFP-237 is minor, the identification problem with SFP-5 through SFP-14 is more significant in that these valves are needed to determine the location of spent fuel pool liner leakage. The licensee was made aware of these problems and the description in OI-24. The licensee immediately initiated a change to the procedure to correct the inadequacies.

With regard to OI-24, it is significant to note that no procedure exists for supplementing the SFPCS with the shutdown cooling heat exchangers should the need arise. This capability is described in Section 3.2.5 of

the system description. Moreover, the removable "spool pieces" needed to achieve the SFPCS/shutdown cooling interface are in place; thus, this configuration could be utilized at this time. The inspector discussed with the licensee the possible use of the cooling interface which may be necessary during full core off load in the future and the need for a procedure.

The valve and pump controls, alarms and alarm manual associated with the SFPCS were reviewed for each SFPCS alarm to determine if adequate guidance was available to operators to cope with off normal (alarm) conditions. All SFPCS alarms were verified to be properly addressed in the alarm manual except as follows: alarm window K-20, "SFP Level Temp HI" does not specify operator action in the event that high spent fuel pool level is detected. The licensee provided a corrective change to the alarm manual when notified of this condition.

Plant procedures were reviewed to determine if the licensee is in compliance with the surveillance requirements of Technical Specifications (TS) as follows:

-- TS 4.9.1(1) and (2) Fuel pool reactivity requirements, are satisfied by performance of Procedure NEP-1, Revision 8 (Nuclear Engineering Procedure - "Incore Fuel Management"). Calculations were reviewed for boron concentrations to maintain K effective less than .95 for Units 1 and 2 cycles 5 and 6;

-- TS 4.9.11 Spent Fuel Pool Water level requirements are performed by STP-0-87-1 "Borated Water Source Operability Verification". A random sampling of data obtained during 1985 indicate that this weekly surveillance interval is being observed. Additionally, TS 3.9.2 minimum source range neutron detectors is ascertained on shift logs and in STP-0-61 "Source Range Instrument Functional Test" and OP-5 Mode 6 checklist; and

-- TS 3.9.4 regarding Refueling Containment Integrity is verified by STP-0-55A "Containment Integrity Verification. A review of the above surveillances was performed for those associated with the Unit 1 1985 Spring outage. No inadequacies were identified.

Corrective and preventive maintenance programs for the SFPCS were reviewed for electrical/instrumentation and mechanical components. Preventive maintenance is performed on all temperature instruments (PM No. 1-67-I-RQ5-100) and pressure instruments (PM Nos. 1-67-I-RQ5-101 and 1-67-I-SA-102). The inspector could not identify level instrumentation as part of the preventive maintenance program. Level instrumentation provides an important indication of off normal (alarm) conditions (i.e., as identified in IE Bulletin regarding cavity seal failures) and therefore should be part of the preventive maintenance program. Electrical preventive maintenance includes the SFPC pump breakers 52-1411 and 52-2411 (PM Nos. 1-67-E-2R-1 and 1-67-E-2YR-1). A "search" using the licensee's computerized corrective maintenance system indicated a backlog of only two items requiring corrective maintenance for electrical/instrumentation components. Both items had been recently identified.

The mechanical preventive maintenance program only includes the SFPC pumps (PM Nos. 2-67-M-A-2 and 2-65-M-A-3). No motor operated or control valves are used in the SFPCS. A print out of outstanding mechanical corrective maintenance items (and a list of items not yet entered into the computer system) indicated only a few items, mostly leaky valves.

With the exception of the water level instrumentation addressed previously, the preventative and corrective maintenance programs for the SFPCS appear to include the correct components and appears to be keeping pace with identified failures.

In conclusion, the SFPCS appears to be a well documented and well maintained system. Procedures for system operation and diagnosis of off normal conditions appear adequate for their purposed. The licensee appears to be in compliance with applicable regulatory requirements and is up to date on preventative and corrective maintenance.

No inadequacies were identified.

19. Review of Hydrogen Recombiners

During the period a review was conducted of the hydrogen recombiner and the hydrogen purge systems. Accessible valve positions and component conditions were examined. Power supplies, breaker alignments and a visual inspection of major components were performed. Operability of instruments essential for system performance was assessed. The inspector reviewed the surveillance test procedures for the hydrogen recombiner system. The review conducted specifically addressed the adequacy of the surveillances in meeting the intent of Technical Specifications for the hydrogen recombiner system. The following procedures were reviewed:

-- STP 0-28-1 & 2 Hydrogen Recombiner Semi-annual Functional Test.

-- STP 0-58-1 & 2 Hydrogen Recombiner 18-month Functional Test.

-- STP M-580-1 & 2 Hydrogen Recombiner Instrument Checks.
-- STP M-581-1 & 2 Hydrogen Recombiner Inspection

A review of system descriptions and FSAR indicated the system was well defined and reflected actual system status. Technical Specifications 4.6.5.2 Hydrogen Recombiner Surveillance Requirements were reviewed relative to the above surveillance procedure. All specifications were adequately addressed. A tour of Containment during shutdown conditions revealed that the H_2 Recombiners appeared in good condition.

During the review of STP-M-581 it was noted that no acceptance criteria or documentation of results of a visual inspection is found in the procedure. The procedure does required that the applicable inspection be performed and does contain acceptance criteria for resistance readings on the heater coils. Inclusion of documented results of the required TS 4.6.5.2(b)(2) visual inspection in the applicable procedure is unresolved

(317/85-28-04). The inspector noted as a positive attribute that the licensee trends TS related Hydrogen Recombiner parameters and reviews this data quarterly.

No other inadequacies were noted.

20. Measuring and Test Equipment (MTE) Program Review

On October 10, 1985 the inspector discussed the MTE Program with the MTE Supervisor, the Instrument & Control Supervisor, and MTE technicians. A review of several instruments, both portable and installed was performed for the following: traceability to the calibration source; as found and as calibrated data; identification of standards used; identification of calibration procedures used; limitations on use; date of calibration; date of next required calibration; and name of person performing calibration.

The inspector noted that the MTE shop appeared very well organized, with formal controls for almost all aspects, and close adherence to Quality Assurance Procedure (QAP-17) "Control and Calibration of Measuring and Test Equipment".

The department maintains records of the calibration standards used and their traceability to nationally recognized standards (National Bureau of Standards, NBS). Instrument errors and accuracies of these calibration standards are controlled to a significantly greater conservative margin than the MTE instruments being calibrated. The accuracy for the standards is required to be a minimum of four times more accurate than the instrument being calibrated; however, many are often ten times more accurate.

Storage of test equipment is generally good. Controls are derived from Military Standards and Institute of Nuclear Power Operations guidelines for Control of Calibration standards and shop calibration equipment.

The only significant weakness noted in the program involved the control of the equipment, in that: no formal controls exist which prevent the use of uncalibrated equipment; no formal policy or statements stating MTE must be in calibration prior to use; no controls exist to prohibit use of MTE by unauthorized or unqualified personnel or for unauthorized usage, i.e., wrong meter on wrong equipment.

The inspector noted while inspecting stored MTE that personnel in the equipment storage room kicked boxes with MTE enclosed and some rough handling occurred. Also noted were battery operated equipment on "charge" within the shelves of the equipment store room. This should take place in a designated well ventilated area. The control of issuance/usage of MTE is on the "honor" system, which requires personnel to log equipment in and out on a usage log and fill out several required entries, most were illegible. This control does not provide adequate assurance that MTE is being recorded when used or for what use. The controls associated with the issuance/use of MTE need improvement. The inspectors will follow the licensee's action in regards to these controls (317/85-28-05).

21. 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:

-- August and September Operations Status Reports for Calvert Cliffs No. 1 Unit and Calvert Cliffs No. 2 Unit, dated September 11, 1985 and October 7, 1985, respectively.

-- Revision to June and July Operating Data Reports for Calvert Cliffs No. 2 Unit, dated August 23, 1985.

-- October Operations Status Reports for Calvert Cliffs No. 1 Unit and Calvert Cliffs No. 2 Unit, dated November 6, 1985.

22. Unresolved Items

Unresolved items require more information to determine their acceptability and one such item is discussed in Detail 19.

23. 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.

ATTACHMENT 1

SAFETY VALUE NUMBER	TS SETPOINT	MAX ALLOWABLE	ACTUAL LIFT PRESSURE	ERROR	TOTAL DRIFT
4000	985 ± 1%	995	1037	42	52
4001	985 ± 1%	995	1040	55	65
4002	995 ± 1%	1005	1059	54	64
4003	995 ± 1%	1005	1047	42	52
4004	1015 ± 1%	1025	1070	45	55
4005	1015 ± 1%	1025	1054	29	39
4006	1035 ± 1%	1045	1104	59	69
4007	1035 ± 1%	1045	1106	61	71
3992	985 ± 1%	995	991	--	6
3993	985 ± 1%	995	1015	20	30
3994	995 ± 1%	1005	1001	--	6
3995	995 ± 1%	1005	1035	30	40
3996	1015 ± 1%	1025	1024	--	9
3997	1015 ± 1%	1025	1020	--	5
3998	1035 ± 1%	1045	1044	--	9
3999	1035 ± 1%	1045	1057	12	22