U. S. NUCLEAR REGULATORY COMMISSION
Region I

Docket/Report: 50-317/86-07 License: DPR-53
50-318/86-07 DPR-69

Licensee: Baltimore Gas and Electric Company

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

Inspection at: Lusby, Maryland

Dates: March 4 - April 30, 1986

Inspectors: T. Foley, Senior Resident Inspector
D. C. Trimble, Resident Inspector

Approved: Elie D. Cabe, for 6/5/86
L. E. Tripp, Chief, Reactor Projects Section 3A Date

Summary: March 4-April 30, 1986: Inspection Report 50-317/86-07,50-318/86-07.

Areas Inspected: Extended inspection due to the routine nature of operation. Inspection consisted of routine observations defined by the I.E. Manual Chapter 2515 program and included inspection of the Control Room, accessible parts of plant structures, plant operations, radiation protection, physical security, Emergency Preparedness Drill, plant operating records, maintenance surveillance, TMI Action Plan Items, reports to the NRC, and allegations regarding Health Physics controls. Inspection hours totalled 240.

Results: The most significant concern identified during this period centers about the increasing trend of steam leaks in the secondary portion of Unit 1. The licensee's program may not be being implemented with sufficient urgency as the problem warrants. This presents significant personnel safety concerns and requires increased licensee emphasis.

Four violations were identified, two of which appear to be of minor significance. Placing of calibration due dates on instruments has been a long-standing issue with the resident inspectors (Detail 7 and UNR 317/82-12-02). Problems with losing shutdown cooling require additional emphasis and may become more significant if not rectified (Detail 4.a). Controls for development of post-maintenance test procedures to ensure that appropriate prerequisites and precautions are incorporated and better reviews performed prior to implementation of the procedures are needed. All technicians need to ensure that only accurate and reliable instruments are used for demonstration of operability (Detail 8). Security should place less reliance on contractor self regulation (Detail 13). Allegations of inadequate Health Physics controls appear to be substantiated.

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

At the beginning of the period, both units were operating at full power. On March 13, an Emergency Response Drill for licensee personnel was conducted.

Unit 1

On March 17, Unit 1 was shut down to commence a five-day planned outage in order to repair a suspect reactor coolant pump seal, a leaky pressurizer relief valve and power operated relief valves, and main steam line drain and salt water system leaks. The unit was returned to power on March 24, limited to 90% power until repairs to one circulating water pump were completed. The unit was returned to full power on March 25.

On April 1, portions of No. 11 moisture separator reheater (MSR) first stage level control line were encapsulated due to their being below minimum wall thickness. On April 18, a rupture of No. 12 MSR drain tank normal level control line occurred. On April 22, No. 11 MSR was taken out of service to enhance the safety of those personnel repairing the No. 12 MSR control line rupture. On April 23, No. 11 MSR high level dump line to the condenser developed a circumferential rupture and consequent steam leak.

Unit 2

On March 17, the unit experienced main turbine vibration problems and was brought to hot standby in order to balance the turbine. The unit was returned to power operations the same day.

On March 25, No. 23 MSR vent line developed a steam leak; repairs were completed two days later.

3. Licensee Action on Previously Identified Items

(Closed) Inspector Follow Item (317/84-31-04). The licensee has identified the root cause of the Failures of the Main Steam Isolation Valves, and has performed repetitive satisfactory testing of the MSIVs. This item is closed.

(Closed) Violation (317/85-01-01). Accesses to High Radiation Areas in the overhead within the controlled areas have been routinely inspected. The licensee has been maintaining adequate control over barricades and postings. This item is closed.

(Closed) Inspector Follow Item (317/85-01-02). The licensee now posts areas within the Auxiliary Building to provide information on abnormally high radiation areas or radiation areas subject to change. This item is closed.

(Closed) Inspector Follow Item (317/85-02-03). A review of the licensee's controls for minimizing energized annunciators on the control board has been conducted. Energized annunciators are generally kept to a minimum. 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.

Loss of Shutdown Cooling and Corrective Action

On March 22, 1986, at 7:45 p.m., Unit 1 was in Mode 5 on shutdown cooling with Reactor Coolant System pressure at 210 psia and 149 degrees Fahrenheit temperature. Maintenance instrumentation technicians were performing a post-maintenance test under maintenance order (MO) #206-084-679A to lift a recently installed electromatic relief valve (ERV 404). The MO required performance of Section V of STP-M-572B-1, Revision 7, "Pressurizer Relief Valve Channel Calibration". As required by the test procedure, technicians behind the control boards inserted a greater than 300 psia signal to pressure indicator/controller PIC 103-1 (EIIS PIC). PIC-103-1, besides providing a signal to ERV 404 (EIIS RV 20) is also interlocked with motor operated valve (MOV) 652 (EIIS ISV 20) to protect the shutdown cooling system from overpressurization. The normal operating pressures for shutdown cooling is 300 psig and the maximum operation pressure is 335 psig. The test procedure provided no direction to block the signal to MOV 652. MOV 652 functioned as designed with this input signal and closed causing termination of shutdown cooling flow. The reactor operator noted the annunciator indicating the loss of flow and secured the No. 12 LPSI pump. I&E technicians immediately reduced the input signal to less than 300 psi to allow re-opening of MOV 652 which operators immediately did after the valve had completely shut.

No. 12 LPSI pump was restarted approximately one minute after termination of flow. Investigation of this event revealed that the procedure used to test ERV 404 was extracted from a section of a surveillance test procedure (STP-M-572B-1), Pressurizer Relief Valve Channel Calibration. STP-M-572B-1 is usually performed during shutdowns, before shutdown cooling is established, to ensure that the reactor coolant system is protected from over-pressurization at low temperature and, therefore, does not address shutdown cooling flow protection.

Preparation of the post maintenance test and associated reviews were apparently inadequate. Each section of STP-M-572B-1, except Section 5, requires that, as a precaution, a jumper be installed prior to inserting a signal greater than 300 psia equivalent in order to prevent MOV 652 from shutting. Section 5 of the STP did not contain prerequisites, precautions or other controls for ensuring that MOV 652 would not be closed by the test input signal.

The inspector noted that several losses of shutdown cooling have occurred periodically during the past several years. Losses due to inadequate procedures occurred on November 1, 1985, identified in Inspection Report 318/85-28 and most recently on March 22, 1986 identified in the above paragraph of this report.

The inspector also recalled a recent Analysis and Evaluation of Operating Data (AEOD) case study "Decay Heat Removal Problems at U.S. PWRs", C-503, dated December 1985, which cited Calvert Cliffs as losing shutdown cooling more frequently than most other plants in the study.

The inspector reviewed the losses of shutdown cooling with plant operations personnel. Most losses occur while the reactor vessel is drained to the center line of the hot leg nozzle. During the procedure for draining, instrument accuracies and the piping configuration and reactor design are such that time delays are experienced in obtaining accurate level readings. At times when an appropriate inventory of water has been removed and the lowering of level has terminated, the level may suddenly change a few inches. These types of level changes have caused pump cavitation or flow instabilities which the licensee conservatively classifies as a loss of shutdown cooling. Other times, an operator may secure one cooling pump before starting the adjacent pump in order to alternate pumps thereby terminating flow momentarily which the licensee conservatively interprets and reports. It is recognized that Technical Specifications permit, during certain modes of operation, termination of shutdown cooling for extended periods of time. However, several incidents in the past have resulted from inadequate procedures or have progressed in an uncontrolled manner, which if they had gone uncorrected, could have resulted in more serious consequences.

In the past, licensee corrective actions to prevent the recurrence of the incidents have consisted of minor procedural changes and counseling technicians. This action appears to be ineffective.

10 CFR 50 Appendix B Criterion V, "Instructions, Procedures and Drawings," requires that activities affecting quality be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and be accomplished in accordance with these instructions, procedures or drawings.

Contrary to the above, on March 22, 1986, a post-maintenance test of 1-ERV-404 was accomplished by procedures not appropriate to the circumstances resulting in the inadvertent isolation of the Unit 1 shutdown cooling system.

Additionally, 10 CFR Appendix B, Criterion XVI, "Corrective Actions," requires that measures shall be established to correct failures, malfunctions and deficiencies, and in the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition.

Contrary to the above, the loss of shutdown cooling event, a significant adverse condition which occurred on November 1, 1985, and which was caused by instructions inappropriate to the circumstances, recurred on March 22, 1986, due to procedures inappropriate to the circumstances. Additional events leading to the loss of shutdown cooling have occurred on June 2, 1985, January 4 and 7, 1983, and October 12, 1983. This is a combined violation of one event failing to comply with two separate requirements (317/86-07-01; 318/86-07-01).

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:

-- Unit 2 Auxiliary Feedwater System checked on March 11 and April 8, 1986.

-- Unit 1 High Pressure Safety Injection System checked on March 18 and April 22, 1986.

-- Unit 2 High Pressure Safety Injection System checked on March 18 and April 22, 1986.

-- Unit 1 Auxiliary Feedwater System checked on March 11 and April 8, 1986.

No violations were identified.

c. Biweekly Inspections

During plant tours, the inspectors observed shift turnovers; boric acid tank samples and tank levels were compared to the Technical Specifications. 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

Emergency Planning Drill

On March 13, 1986 the licensee conducted an Emergency Plan drill simulating a security event and a loss of coolant accident. Participation of outside agencies was limited to telephone notification only. One participant received a minor injury during the drill resulting in an actual medical emergency event response. All levels of plant management (through the Vice President level) participated in the drill and all emergency and media centers were manned. The inspector observed portions of the drill and attended a pre-drill controller meeting and the post-drill critiques. No significant weaknesses were identified by the inspector.

No violations were identified.

5. Low Pressure Steam Line Leaks/Ruptures and Failures

Low pressure steam line problems have been manifested in pin-hole leaks and ruptures including one circumferential break. Those occurring during this period include:

-- March 25: Steam leak No. 23 Moisture Separator Reheater (MSR) vent line (Unit 2);

-- March 27: Pin-hole leak in weld on No. 11 MSR Drain Tank level control line (Unit 1);

-- April 17: Rupture of No. 12 MSR Drain Tank normal level control line (Unit 1); and

-- April 25: Circumferential failure of No. 11 MSR high level dump line to condenser (Unit 1).

Pin-hole leaks have been attributed to localized accelerated erosion caused by steam flow eddies resulting from weld backing rings and penetrations such as thermometers.

Pipe ruptures occurring in Unit 1 include the third stage extraction steam line in November 1981, No. 15 extraction steam line in November 1984, and the most recent MSR drain tank level control line in April 1986. In October 1981, the Unit 1 25 to 26 feedwater heater 14-inch to 6-inch reducer drain line ruptured.

Low pressure steam drain line elbows carrying high moisture content steam such as those from MSRs and extraction steam lines are most subject to this erosion failure. Reasons for Unit 1 experiencing more failures would seem to include an apparently more convoluted steam drain system in Unit 1 than Unit 2, the older age of Unit 1, and the use of schedule 40 pipe in Unit 1 where

schedule 80 pipe is used in Unit 2. The design of each unit's drain system with respect to pressure reducers, flows and velocities may be a contributor to the different failure rate.

The licensee recognized the problem and initiated an ultrasonic testing (UT) program in 1984. This program defined approximately 6000 locations to be inspected and divided them into high, medium, and low priority, based on most probable locations as determined by EPRI, Gilbert Commonwealth, and Bechtel studies, and licensee experience. The program continues only when a unit is shut down for outage or upon special request, and then the system must be isolated and cooled down in order to UT the pipe. Currently, 90% of the high priority locations on both units have been inspected. On Unit 1, this is 290 locations of which 57 locations were below the licensee's administrative acceptance criteria which rejects any point below 150 mils. ASME code minimum wall thickness for this application is .090 inches and pipe ruptures generally begin to occur at or below .030 inches. Unit 2's inspection program has thus far resulted in 367 locations of which 52 were rejected. The program has caused the replacement of about 900 feet of piping to date. Several complete pipe runs of low pressure drain line pipe are scheduled for replacement during the upcoming outage with chrome-moly alloy schedule 40 pipe. Schedule 80 pipe is not used to replace the schedule 40 pipe in Unit 1 due to the complications which would arise in re-analyzing the pipe support system. The licensee management is aware of and concerned about the potential personnel hazards associated with the erosion problem.

The third problem is associated with vibration of the high pressure main steam lines, low pressure extraction steam and drain lines, and high temperature feed water lines. Through observations, the licensee has noted apparent excessive vibration in several areas of the plant. Efforts to reduce the vibration in the past have been to design and install additional supports. Significant reduction was not evident and the licensee remained concerned. As a result, the licensee contracted Bechtel Power Corporation to perform an engineering evaluation of piping vibration and support systems for the main steam and heater drain system. This included a walk down inspection of the piping systems to inspect the piping from a vibration and support integrity viewpoint. Specific tasks included:

-- Vibration measurements at selected locations on main and auxiliary piping in the Unit 1 and Unit 2 turbine building for comparison with prior measurements made in October 1985.

-- Inspection of main steam piping supports and ancillary piping in the turbine building of both units.

-- Inspection of MSR drain piping systems in both units.

Results of the evaluation required installation of supports in 24 areas, 9 of which were required immediately, 12 are to be implemented pending completion of design studies underway, and 3 for long term consideration.

The study concluded that, in general, the main steam piping supports are in good condition except as noted, and appropriately located to resist dynamic forces resulting from the main steam flow. Localized areas of high vibration in bypass headers and small branch lines, resulting in some loosening and wear of support components, have been identified and are presently under investigation for design of additional restraints as required. Localized areas of excessive motion of MSR drain piping have also been identified and are under investigation. Upon completion of this work, confirming vibration measurements and a program of periodic inspection of support conditions should assure that there are not problems with the piping support system.

On April 23, 1986, Unit 1 No. 11 MSR high level dump line to the condenser was found leaking steam. Subsequently, it was determined that a circumferential break had occurred but the pipe was apparently "cold sprung" in the direction of the condenser, minimizing steam leakage or air in-leakage to the condenser. This line had been identified as one of twelve requiring a support to be designed before installation. A program to study hangers and other supports for high capacity steam lines and high temperature fed lines is being developed and will be implemented during the next refueling outage.

6. Review of Licensee Event Reports (LERs)

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

LER No.	Event Date	Report Date	Subject
Unit-2			
86-01	01/20/86	2/20/86	Violation of Technical Specifications for Pressurizer Overpressure Protection during Cold Shut Down Conditions
86-02	2/4/86	2/28/86	Inadvertent Trip of Main Turbine from Engineering Safety Features Actuation System
86-03	3/15/86	4/11/86	Inadvertent Engineered Safety Features Actuation Due to Failed Logic Module

7. Plant Maintenance

The inspector observed and reviewed maintenance and problem investigation activities to verify compliance with regulations, administrative and maintenance procedures, codes and standards, proper QA/QC involvement, safety tag use, equipment alignment, jumper use, personnel qualifications, radiological con-

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

-- MO 206-059-133A, MSIV-2 Accumulator Bladder Removal, Inspection and Reassembly of No. 8 Accumulator 21 MSIV.

-- MO 206-11-382A, No. 11 Control Element Drive Mechanism Motor-Generator Set Bearing Replacement/Repair.

-- MO 206-111-300A, No. 23 Auxiliary Feedwater Pump Bearing Temperature Rise Investigation.

Calibration Stickers

During the performance of STP-073-01, as subsequently discussed in paragraph 8, operators utilized an out of calibration gauge to determine operability of No. 11 HPSI pump.

Review of this resulted in a violation due to use of an uncalibrated gauge that was inappropriate to the circumstances. Further review of the gauges indicated that personnel performing the test are unable to readily determine whether gauges are calibrated or not in that calibration stickers are not used on installed instruments.

This topic had been previously discussed with the General Supervisor, Electrical and Control Department. The supervisor referenced ANSI 45.2.4 to which the licensee is committed through the Baltimore Gas and Electric Quality Assurance Manual. He highlighted that the standard which requires that installed instrumentation be provided with tags or stickers indicating the date due of next required calibration, is a construction standard applicable to plants in a construction phase and is not applicable to Calvert Cliffs in its current phase of operation.

Further research and examination of other utilities for use of calibration stickers on installed instrumentation revealed that other facilities examined utilize calibration stickers both in the control room and in the plant and comply with ANSI 45.2.4 and IEEE 336. Further, the licensee's QA Manual requires compliance with Regulatory Guide 1.30 which specifies that ANSI 45.2.4 be applicable to operating power plants as well. The licensee's failure to implement the requirements of ANSI 45.2.4 and IEEE 336 is a violation (317/86-07-02; 318/86-07-02).

8. Surveillance

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-073-01, Engineering Safety Features Equipment Performance Test.

-- STP-M-572-1, Pressurizer Relief Valve Channel Calibration.

-- STP-05-1, Auxiliary Feedwater Pump.

-- STP-0-65-1, Quarterly Valve Operability Check.

-- STP-M-77-0, Diesel Fire Pump Surveillance.

-- STP-0-90-2, Emergency Diesel Generator No. 21 Operability Test.

On March 10, Unit 1 was at 100% power. The licensee was in progress of performing STP-073-01 "Engineering Safety Features Equipment Performance Test", Revision 23. During performance of Section (E) 11 High Pressure Safety Injection (HPSI), the procedure requires determination of "Pump Head" by recording and subtracting the suction pressure from the discharge pressure utilizing PI-301Z as the discharge pressure instrument (located in the Control Room). PI-301Z, "13 HPSI Discharge Pressure Gauge" had attached to it an "MR" sticker No. 3994 dated February 23, 1986, stating "13 HPSI in Action Range due to 1-PT-301 out of cal". The needle of the gauge also appeared to be inappropriately centered below the lowest indicating increment, i.e., zero. Performance of the STP continued utilizing this gauge. Consequently, the acceptance criteria for Pump Head (TDH) 2900 Ft. was not met, i.e., as found data, suction pressure 42 psi plus .89 factor (correction factor in psi due to gauge location) subtracted from 1180 discharge pressure plus .65 factor provide a differential pressure D/P of 1137.8 psig or 2633.9 Ft. Pump Head.

Based upon the failure to meet the Pump Head acceptance criteria, the Shift Supervisor appropriately declared the HPSI Pump No. 11 inoperable. Subsequently, operators noted that the discharge pressure gauges for HPSI pumps 12 and 13 (subject to the same pressure) were consistent and indicated several pounds pressure higher than PI-301Z. Noting this, the pressure from HPSI pumps 12 and 13 was used to justify acceptance of operability in lieu of HPSI pump 11 pressure gauge and the pump was declared operable.

The inspector noted the above and discussed the same with the Shift Supervisor, and noted that although the pump appeared operable based on the above observations, formal determination of operability can only be determined by successful completion of a performance test. Therefore, the test should be repeated and a change should be approved and inserted providing for use of the alternate gauges.

Consequently, later during the day, Section E of the test was repeated without inserting a change and the pump re-declared operable.

10 CFR 50, Appendix B Criterion requires that instrumentation appropriate to the circumstances be utilized to demonstrate compliance with requirements. Contrary to this, STP-073-01 was initially performed to demonstrate compliance with Technical Specifications for operability utilizing a gauge inappropriate

to the circumstances in that the gauge was known to be deficient by evidence of the Maintenance Request (MR) adhered to it. This is a violation (317/86-07-03).

The inspector noted that guidance should be promulgated to ensure that (1) tests are not performed utilizing instruments that are suspect for any reason, (2) operability can only be determined via completion of a successful test procedure, and (3) procedures for making temporary changes to test procedures should be re-emphasized.

9. Safety Review Committee Meetings

During the period the inspector attended several Plant Operations and Safety Review Committee (POSRC) meetings and the quarterly Off Site Safety Review Committee (OSSRC) meeting held on March 27, 1986.

The inspector observed each meeting for compliance with Technical Specifications and ANSI 45.2 and for its apparent effectiveness in utilizing group synergism.

POSRC meetings appear to be improved since the management change of January 1986, in that:

(1) The Chairman allows more discussion between POSRC members with little comment until the end of discussion, then separately solicits a recommendation, thereby forcing the POSRC to act in an advisory role as required.

(2) Changes were made to reduce the number of personnel in the conference room, making the environment less crowded.

(3) POSRC Chairman appears to be more critical, and leads the members in asking more probing questions resulting in many items being returned for additional analysis or work.

POSRC meetings appear to meet Technical Specifications and are effective.

Attendance at the Off Site Safety Review Committee, OSSRC, meeting held at the "The Eagles Den" on site revealed that the meeting appeared to have fewer people in attendance and less formality than OSSRC meetings held in Baltimore. Those present did, however, ask thought provoking questions with good interaction between members.

Review of the OSSRC members' expertise indicated that no personnel were present at the meeting who had expertise in metallurgy or non-destructive examination. During discussions with the the licensee, the inspector indicated that formal controls should be established to establish acceptance criteria for what topics must be deferred when the person with accredited expertise is not present.

Technical Specifications require that the OSSRC be composed of certain members with specific expertise. Review of the licensee's matrix for accrediting experience and the resumes of the members indicated that anyone who had attended Naval Nuclear Power School was accredited with expertise in Operations, Health Physics, Nuclear Engineering and Chemistry. The inspector discussed this with the licensee and took exception with this policy in that many persons were accredited with "Nuclear Engineering" but only a very few had had actual experience in dealing with the subject. Others accredited with "Health Physics" had had little or no more experience than the average radiation worker, and very experienced people with degrees and experiences are available on site.

The inspector requested the licensee to re-evaluate the matrix for accrediting experience.

No violations were identified.

10. 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 items were reviewed.

-- Item I.C.1 Short Term Accident and Procedure Review. This item has been addressed in Inspection Report 317/80-05; 318/80-08 and 317/85-24. The licensee has completed all aspects of this item. The procedures are currently in the Control Room for operator use, and one cycle of training has been completed. A revised due date for this issue was established as December 31, 1985, by a Confirmatory Order to the licensee dated July 16, 1985. Procedure implementation was in effect at this time. This item is closed.

-- Item II.B.1 Reactor Coolant Vent System. This item was addressed in Inspection Report 317/82-05; 318/84-07. The system is currently acceptable and considered closed. Additional items associated with the system are as follows:

(1) Emergency procedures for operation of the Head Vent are not in the new symptoms format utilizing the Owners Group Emergency Guidelines (tracked under Item I.C.1). Previously established procedures currently exist for operation of the system. Also, EOP-8 "Functional Recovery Procedure" makes reference to OI-1 G "Reactor Coolant Vessel Head and Pressurizer Vent System" which provides for the operation of the system. This item is closed.

No inadequacies were identified.

11. Radiological Controls

Radiological controls were observed on a routine basis during the reporting period. Standard industry radiological work practices and 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.

Allegation

During this period on April 17, 1986, an anonymous allegation was made regarding possible unauthorized entry into a High Radiation area on the 5 foot West Penetration area of Unit 2. This information was immediately transmitted to NRC Regional Management. A preliminary inspection was conducted. The investigation included discussions with the Supervisor-Radiation Controls, the Radiation Controls Shift Supervisor, the Instrument and Control Supervisor and the persons involved. Results of these inquiries were transmitted to the NRC regional office staff.

A second part of the allegation was received by the resident inspector on May 6, 1986, regarding the uncontrolled use of High Radiation area keys. The alleger informed the inspector where a set of uncontrolled keys could be located. The inspector obtained the set of keys and, together with the Manager of Operations and Health Physics Supervisor, ascertained that these keys, in fact, could provide access to locked High Radiation areas. The keys were turned over to the licensee. A telephone conversation was held between the Vice President, Nuclear Power and NRC management regarding these allegations. An NRC letter was went to Baltimore Gas and Electric dated May 6, 1986, requesting a response and a description of corrective actions, if appropriate.

Immediate corrective actions on the part of the licensee consisted of changing all of the locked High Radiation area doors (about 17) with radiation levels greater than 100 mr/hr. An additional 17 door locks were changed where radiation levels vary significantly. Thirty-five padlocks are also being changed on licensee controlled sources and other sensitive items/areas.

Technical Specifications 6.12 requires that keys to High Radiation areas required to be locked shall be under the separate administrative control of the Supervisor-Radiation Control and the Operations Shift Supervisor. Resolution of this item is pending the licensee's response to the NRC May 6 letter. This item is unresolved (318/86-07-03).

12. 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; determina-

tion whether any information should be classified as an abnormal occurrence, and validity of reported information. The following periodic reports were reviewed:

-- February and March Operating Data Reports for Calvert Cliffs No. 1 Unit and Calvert Cliffs No. 2 Unit, dated March 7 and April 8, 1986, respectively.

13. Observation of Physical Security

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

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14. Unresolved Items

Unresolved items require more information to determine their acceptability and one such item is discussed in Detail 11.

15. Exit Interview

Meetings were periodically held with senior facility management to discuss the inspection scope and findings. A summary of findings was presented to the licensee at the end of the inspection.