

U. S. NUCLEAR REGULATORY COMMISSION  
REGION I

Docket/Report: 50-317/86-09  
50-318/86-09

License: DPR-53  
DPR-69

Licensee: Baltimore Gas and Electric Company

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

Inspection At: Lusby, Maryland

Dates: May 1 - June 30, 1986

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

Approved:

*L. E. Tripp*  
L. E. Tripp, Chief, Reactor Projects Section 3A

7.31.86  
Date

Summary: May 1 - June 30, 1986: Inspection Report 50-317/86-09, 50-318/86-09.

Areas Inspected: Routine resident inspection of (1) facility activities, (2) previous inspection findings, (3) plant operations including Feed Water System problems and RCP vibration, (4) physical security, (5) Licensee Event Reports, (6) maintenance, (7) surveillance, (8) responses to selected safety issues, (9) radiological controls including: (a) allegations regarding key control and "jimmying" high radiation doors, and (b) review of radiological environmental monitoring report by regional specialist inspector Struckmeyer. Inspection hours totalled 247 hours.

Results: Allegations received and investigated by the inspector appear to be substantiated, and resulted in a violation regarding control of locked High Radiation Area Keys, Section 9 of this report.

Pursuit and identification of the root cause of reactor trips on May 21 and 27 appeared untimely. Many indications pointing toward the cause of the problem occurred before sufficient licensee action was taken to resolve the problem. A comprehensive resolution was eventually achieved.

Reactor Coolant Pump shaft vibration problems slowly increased in magnitude. Licensee attention increased proportionally, with plans for a mini-outage and a shutdown imminent (within 2-3 days). However, the vibration amplitude subsided postponing the need for a shutdown. Licensee monitoring and actions appear appropriate.

## DETAILS

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

### 1. Summary of Facility Activities

#### Unit 1

Unit 1 was at full reactor power (825 MWe) at the beginning of the operating period. Except for minor power reductions for preventative maintenance and surveillance and the events noted below, Unit 1 remained at full power throughout the period. From May 16 to May 19, 1986 the unit was at reduced power (790 MWe) for installation of a new type of traveling screen. On June 20, power was reduced to 1% to permit a containment entry to add oil to No. 12A Reactor Coolant pump upper oil reservoir. The unit returned to 100% power operation on June 22, 1986 and operated at full load for the remainder of the month.

#### Unit 2

Unit 2 began the operating period at full reactor power (825 MWe). The unit was manually tripped on May 21, 1986, because of a loss of Steam Generator Feed Pumps (SGFP). The cause of the loss of the SGFPs was not determined. On May 23, 1986 the unit was paralleled to the grid.

On May 27, 1986, the unit was automatically tripped due to loss of SGFPs. On May 28, 1986, the unit was paralleled to the grid and remained at 60% power (520 MWe) to test the SGFP instrumentation. Testing of the SGFP instrumentation remained in progress from May 28, 1986 until June 7. The unit then returned to 100% power and operated at full load for the remainder of the month.

The licensee conducted an Emergency Response Drill on June 12, 1986.

### 2. Licensee Action on Previous Inspection Findings

(Closed) Unresolved Item (317/84-05-01) Post Accident Sampling System (PASS) Tubing Exposed and Presents Potential Radiation Scatter Dose Contribution. The Combustion Engineering provided PASS system (the scatter source) is no longer used by the licensee to satisfy post accident sampling requirements. Samples are drawn at the normal sample station and transported to the chemistry lab for analysis. This item is closed.

(Closed) Unresolved Item (317/83-26-01) Surveillance Test Procedure 0-7-1, "Engineered Safety Features Logic and Performance Test", Indicates That Pressurizer Heater Breakers 52-1127 and 52-1427 Open On Automatic Action (SIAS subchannel A-4); However Updated FSAR Does Not Reflect This. Revision 3 to the Updated FSAR added these breakers to the subchannel A-4 component listing. This item is closed.

(Closed) Unresolved Item (318/84-18-04) Technical Specification (TS) 4.8.1.1.2 Requires Clarification Regarding Which Diesel Generator Trips Are To Be Tested For Bypass Condition During Safety Injection Actuation System (SIAS) Actuation. TS Amendment 94 corrected this problem. This item is closed.

(Open) Inspector Follow Item (318/85-28-02) Main Steam Safety Valve (MSSV) Setpoint Drift. This problem is described in Section 11 of Inspection Report 50-317/85-28, 50-318/85-28 and Section 4c of Inspection Report 50-317/85-30, 50-318/85-32. As committed, the licensee checked the setpoints on four Unit 2 MSSV's during "the first outage after four months of operation" (on May 22, 1986). The following results were obtained:

Valve #	Allowable Setpoint By TS (psig)	Previous As Left 12/7/85 (psig)	As Found 5/22/86 (psig)	Setpoint Drift (psig)	Setpoint Drift (%)
3995	935-1035	1004	1007.6	+3.6	0.36
3999	935-1066	1029	1027	-2	0.19
4001	935-995	981	975	-6	0.6
4004	935-1065	1020	1004.7	-15.3	1.5

Percentage drift for these valves was low compared to that seen during the previous operating cycle (drift for these valves had ranged from 2 - 6.5%). Even if drift continued at the current rate, for the remainder of the present cycle, the Technical Specification setpoint limits would not be exceeded. This item will remain open until the licensee completes committed actions on Unit 1 (check setpoints of all Unit 1 MSSV's at next shutdown).

(Closed) Unresolved Item (317/84-01-03) Anomalous Indications On Auxiliary Feed Water Actuation System (AFAS) Panels (Inconsistency in readings for steam generator/steam line differential pressures). The inspector examined the panels during this inspection period and noted that this condition no longer exists. This item is closed.

(Closed) Violation (317/86-03-01) Failure To Maintain Administrative Control Over 1-PS-6529-SV. The licensee has taken the following corrective actions: (1) the responsible chemist was counseled; (2) the event was discussed with chemistry personnel; (3) a personnel incident report of the event was reviewed by and discussed with operations personnel; (4) reinforcing the GSO standing instructions, operations personnel were instructed to carry forward log entries regarding open containment isolation valves between shifts to serve as a reminder of valve status; and (5) to increase personnel responsibility/cognizance for valve control keys, keys are now being signed out to individuals (by name) instead of to organizational groups (e.g., "Chemistry Group). Additionally, the licensee will add manual isolation valves to the sample return lines to the Volume Control Tanks (VCT). These valves will be accessible during all expected radiological conditions and will assure those flow paths can always be isolated. This item is closed.

(Closed) Violation (317/86-07-03) Failure To Utilize Instrumentation Appropriate To The Circumstances. Licensee's actions which rectify this matter are implemented in the Revised General Supervisor Operations Standing Instructions 86-01, dated March 28, 1986 which states the following:

"The following rules apply when performing surveillance testing: Any time a piece of equipment fails a surveillance test we must declare that equipment inoperable and apply the appropriate Technical Specification action statement. If we suspect a surveillance test failed because of a out of calibration instrument, improper valve lineup or any other condition we must still consider the equipment inoperable until the equipment passes a valid surveillance test.

We should never perform a surveillance test using an instrument that is known or appears to be out of calibration. This would be indicated by the presence of a deficiency tag on the instrument relating to its calibration or the instrument obviously indicating incorrectly prior to the test (i.e., a pump indicating normal discharge pressure before it is started).

We must maintain a conservative attitude toward surveillance testing. For example, if an instrument fails its channel check required by the daily logs we must consider the instrument inoperable until it is proven otherwise or fixed."

This matter is closed.

(Closed) Inspector Follow Item (318/84-31-04) Failure To Identify Root Cause Of The Main Steam Isolation Valve Inoperability. The Inspection Report 50-317/85-01; 50-318/85-01 details the follow up action and resolution of this issue. No other inadequacies involving MSIV operability have been noted to date. This matter is closed.

### 3. 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, effluent monitoring, emergency power source operability, control room logs, shift supervisor logs, tagout logs, and operating orders.

No violations were identified.

b. System Alignment Inspection

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

- Auxiliary Feed Water Systems for Units 1 and 2.
- High Pressure Safety Injection System for Unit 2.
- Containment Spray System for Unit 1.
- Emergency Diesel Generator No. 11.

No violations were identified.

c. Biweekly Inspections

During plant tours, the inspector observed shift turnovers; Emergency Safeguards water storage 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 various tagouts indicated the action was properly conducted.

No violations were identified.

d. Other Inspections

Feed Water System Control Problem

Due to (50) feed water losses and 3 significant reductions for both units over a five year period, a task force was formed to study the poor control, erratic operation, slow maneuverability and unplanned trips caused by the feed water control system. As a result, the task force recommended installation of "state of the art" controls.

In November 1985, the Unit 2 steam generator feed pump speed control system was replaced with new Lovejoy controls. The speed control system receives a control signal which is inversely proportional to feed water regulating valve differential pressure. This signal is generated within the feed water regulating valve differential pressure control system (see Attachment-1). Electronic components convert an electrical signal from the differential pressure control system to a pneumatic control signal which in turn regulates high pressure control oil to the feed pump

turbine throttles by means of pneumatic to hydraulic control (cup) valves. The new system is significantly more sensitive than the originally installed equipment and responds to changes much faster.

On May 21, 1986 at 11:00 p.m., with Unit 2 at 100% power, operators noted that No. 21 Feed Water Pump tripped (FWP). Operators immediately manually tripped the reactor to prevent an impending automatic trip of the reactor due to steam generator low water level. Investigation of the FWP trip determined that the pump tripped due to an over speed condition, in that the sequence of events computer print out high discharge pressure indicated a FWP pressure of 1154 psig and the setpoint being 1150. Simultaneously with this event No. 23 Condensate Booster pump automatically initiated as would be expected on a sudden demand by the FWP. Immediately after the plant trip, the remaining (No. 22) FWP tripped apparently on over speed. Operators were able to reset No. 22 FWP and follow normal cool down procedures, however, No. 21 FWP was unable to be reset due to a high pressure stop valve failing to indicate fully closed. (Valve position indication is part of the logic for an equipment protection interlock.) All reactor protection equipment worked as designed. A post trip review was conducted in accordance with Calvert Cliffs Instruction 111-B and determined that the reactor trip was known to be performed manually and that the No. 21 feed pump tripped on over speed, but could not identify the root cause of the feed pump trip. The Plant Operations and Safety Review Committee approved restart of the unit providing the following was first accomplished:

- Check setpoints on high discharge pressure and low suction pressure switches and blow down the associated sensing lines for Nos. 21 and 22 Steam Generator Feed Pumps;
- Determine why 21 Steam Generator Feed Pump high pressure stop valve did not indicate shut after No. 21 pump tripped;
- Install monitors for the output of the differential pressure transmitters, differential pressure indicator controllers, hand indicating controllers, high select instrumentation and the Lovejoy control current to pneumatic converter;
- Check operation of the Steam Generator Feed Pump differential pressure indicator controllers (PDIC's) and associated instrumentation, i.e., hand indicator controllers (HIC's) and pressure differential transmitters (PDT's);
- Check power supplies of the above instrumentation; and
- Perform an over speed trip test of both Nos. 21 and 22 FWPs.

This action was completed and on May 23 Unit 2 resumed normal operations.

The inspector discussed concerns with plant management regarding the failure to identify the root cause of the trip, noting a similar trip in December 12, 1985 during which Unit 2 tripped on low steam generator level from 46% power due to a loss of the No. 21 Feed Water Pump (FWP). The licensee determined that in the December trip, an erroneous FWP control signal caused the pump speed to cycle greatly and resulted in a pump trip on high discharge pressure. Troubleshooting revealed a faulty signal selector (2PY4516) and an intermittent erratic control signal. The signal selector was replaced and trend recorders were installed at several points in the control system to monitor signals prior to start up. The positioners for one feed regulating valve (2CV1111) was later replaced. The erratic signal disappeared and could not be identified or duplicated. The unit was returned to power operation with the pump speed in manual control. The root cause of this December 12 trip also remained unidentified.

The licensee contended that the trips were not related however, stated that additional instrumentation was being placed on various feed water system components to provide additional data to aid in the evaluation and post trip review process should the plant trip again. The inspectors also discussed NRC philosophy and actions taken at other utilities for inadequate or inappropriate licensee action on secondary system problems impacting the reactor protection system. The licensee recognized this and reiterated that the December, 1985 reactor trip was considerably different and the identified failed equipment had been replaced.

Subsequently, at 10:24 a.m. on May 27, 1986, while operating at 100% power, Unit 2 reactor tripped automatically due to low steam generator level. The cause of the low level condition was a result of an automatic trip of No. 22 FWP.

Plant conditions, alarms and equipment functioned as identified in the May 21 event. Because of the previously instrumented feed water system components, the licensee was better able to determine the cause of the FWP over speed condition. Evaluation of brush recorder and plant computer printouts indicated that the FWP was over speeding due to a spurious input signal to the Lovejoy control system generated within the Main Feed Regulating Valve differential main pressure control system. A brush recorder which had been set up to monitor the output of the differential pressure indicator controller in the Feed Water Regulating Valve Differential Pressure Control system, recorded an erratic signal lasting approximately six seconds, which preceded the automatic trip of No. 22 steam generator feed pump.

During the plant trip sequence, the Auxiliary Feed Water system started No. 21 and 23 Auxiliary Feed Water Pumps. Both Auxiliary Feed Water Pumps operated normally on demand. As a result of the reactor coolant system cooldown, the Control Room Operator secured the Turbine Driven pump by shutting the Main Steam Supply Control Valves (2-MS-4070 and 4071 CVs). Following this action No. 21 Auxiliary Feed Water Pump tripped

unexpectedly. The Turbine Building Operator was immediately dispatched to reset No. 21 Auxiliary Feed Water Pump returning it to a normal standby condition.

Immediately following the reactor trip, operators placed the plant in a Hot Standby Condition and a post trip review was initiated. The review concluded that all safety equipment functioned as designed, that there were no significant deviations from expected plant parameters responses, and that the trip was very similar to the May 21 trip. Again, no root cause for the feed water pump trip could positively identified, therefore, the Plant Operations and Safety Review Committee (POSRC) met (Meeting No. 86-40) on May 27 at 4:00 p.m. to discuss the plant trip and problems with Unit 2 feed water system controls. The committee determined that the probable cause of the event was an erratic output from a differential pressure indicator controller (PDIC-4517), aggravated or caused by a loose lead found on PDIC-4517 output in the cable spreading room. The committee approved restart of the unit provided the following conditions were met/investigated:

- Install a high speed Honeywell recorder to monitor selected feed pump control parameters (the previous recorder could not differentiate parameter responses due to its slow speed);
- Monitor bus voltage on 2R01A (power supply to Feed Water Control instruments);
- Investigate why No. 21 Auxiliary Feed Water Pump tripped;
- Thoroughly test PDIC-4517;
- Inspect all wiring connections associated with the feed pump speed control circuitry in 2C03 and the cable spreading room;
- At approximately 50% reactor power, test PDIC-4517 with feed pump controls in manual;
- Test No. 23 Condensate Booster Pump auto start feature for connection with feed pump speed control circuitry; and
- Adjust the maximum speed limit of the Lovejoy controls to 5130 rpm. Keep feed pump controls in manual until the adjustment is made.

Except for follow up troubleshooting, the above conditions were met, and the plant returned to 60% power on May 28 for dynamic testing of the feed system.

The inspector attended several licensee meetings regarding this reactor trip and discussed with the Manager of Operations, NRC concerns regarding the failure to identify the root cause of the feed pump trips. That, notwithstanding the fact that CCI 111-B "Post Trip Review" had been con-



ducted and concluded that reactor parameters responded normally and the cause of the reactor trip was due to low steam generator water level due to the feed water pumps tripping, the root cause probably still existed and might challenge reactor protection system again.

The licensee assured the inspector that the root cause would be identified, and that power operation was necessary to determine the cause of the feed pump trip. However, power would be limited to the capacity of one feed pump (60%) and both pumps would be maintained in manual control, a task force/test group was being assembled to pursue the cause of the feed system problems, and that power would not be escalated nor control placed in automatic until the root cause was fully investigated and resolved.

Subsequently, the above test group and troubleshooting effort during operation at 60% power and revealed the following information:

Reference: Attachment 1. The recorders previously connected to PDIC and PDT 4516 and 4517 were reviewed for response at the time of the event. At the time, PDIC-4517 was in automatic and 4516 was in manual, (a normal configuration during operation). PDIC-4517 a reverse acting controller showed a response in the full output direction initially, followed by a one quarter scale oscillation near the upper range of the scale. PY-4516 basically traced an exact image of PDIC-4517's output (as expected). Recorder traces for PDT-4516 and 4517 show an initial spike in the increasing signal direction followed by a full scale oscillation for PDT-4517 and three quarter scale oscillation for PDT-4516. The licensee concluded that the trace indicated a spurious signal originating at PDIC-4517 in the increasing direction was passed through PY-4516 which in turn caused an increase in the Lovejoy speed control signal to the feed pumps. As a result, feed regulating valve differential pressure increased causing an increase in PDT-4516 and 4517 output (normally this would have resulted in a decrease in the output signal). Based on this response it was believed that PDIC-4517 failed in the high direction eventually causing the feed pumps to over speed.

Instrument Maintenance began troubleshooting the PDIC and PY instrumentation. The PDIC was removed from the control room panel 2C03 and taken to the shop for bench testing. Technicians found one bad loop resistor for PY-4516 output. Terminal board inspections revealed broken strands of wire one strand intact leading to PDIC-4517 and PY-4516. (The licensee initially perceived that this caused the PDIC output problem.) Testing subsequently disproved this. Bench testing was completed and the instruments were reinstalled. Post installation testing of the PDIC at 2C03 determined that a positive ground existed on the 48V DC bus supplying power to the PDIC and PY.

PDIC-4517 was again removed from 2C03 and bench tested in the shop. In an effort trying to duplicate the recorder traces a simulated transmitter signal was applied to the PDIC input terminal while a temporary power

supply was connected. The technician grounded the power supply and observed erratic output from the PDIC. Removing the ground caused the problem to go away. This confirmed that a ground existed in the PDIC. Subsequent bench testing determined that the ground was in a PDIC circuit board, which was eventually replaced with a spare board from stock.

Subsequently, Instrument Maintenance began an evaluation of the 2R01A (48V DC) power supply looking for the cause of the ground. The evaluation involved lifting leads to installed instrumentation and measuring the bus voltage to ground. When the leads to 2-PT-1447 (21A Feed Water Heater Extraction Steam Pressure transmitter) were lifted the ground voltage measured on the positive and negative side of the power leads indicated a -46v, suggesting a positive side ground (later confirmed to be a grounded motor in the transmitter). During the above test the fuse for the pressure transmitter blew. This same fuse had been replaced approximately 5 seconds prior to the time that the reactor trip occurred on May 27. Further testing (involving a check of all instrumentation supplied by 2R01A) between May 30 and June 2 resulted in one additional ground being found on the loop for 2-PT-3966 (22 steam generator feed pump discharge pressure transmitter) which provides a signal for a chart the recorder in the Control Room.

Subsequently, modifications were made on 2R01A to separate the bus supplying power to the two steam generator feed system control loops. These modifications consisted of lifting the power leads at 2R01A and installing two new power supplies.

Additional troubleshooting of the feed pump oil system revealed several problems, i.e., a failed oil sump vapor extractor motor causing leaks around the inboard oil deflector, an outlet flange to the inboard main oil pump oil leak, and a ruptured high pressure governor control oil hose. Additional problems with the "B" system cup valves were apparently causing oscillations in the control oil system. These were subsequently corrected and operationally tested.

Subsequently, between June 2 and 7, 1986 twelve (12) dynamic tests of the feed water pump controls took place. The system was placed in various configurations and transients were introduced while system response was observed. On June 7, all feed pump controls were placed in automatic and reactor power was increased to 100%.

On June 25, Instrument Maintenance implemented a new PM (1/2-102-E-2W-1) to be performed on a 2 week frequency that provides inspections for ground on Unit 1 and 2 busses supply power to various indicator and control loops.

Based on the above problems and troubleshooting efforts, various improvements/tasks were assigned as follows:

- Evaluate an upgrade of the steam generator feed pump control systems for Units 1 and 2 using state of the art technology.
- Evaluate a redesign of the Unit 1 and 2, RO1A electrical distribution system including an automatic ground detection system.
- Evaluate the installation of a trip (first hit-in indication panel for Unit 1 and 2 steam generator feed pumps).
- Evaluate upgrades to the turbine driven auxiliary feed pump trip throttle valve.
- Evaluate elimination of the high discharge pressure trip for Unit 1 and 2, thereby eliminating a potential challenge to the unit.

Numerous other recommendations have been made and are being evaluated, however, are not being formally tracked or were not assigned responsibility.

Discussions with the plant operators, engineers, supervisors and managers, as well as independent observation of feed system performance, indicate that the root cause of the feed system control problems was due to grounds on the power supplies and aggravated by additional grounds on instruments and numerous minor control oil and valve problems. The problems have been identified and corrected. The licensee approach to the resolution of this technical issue initially demonstrated a lack of understanding and pursuit of the problem was delayed. However, once they recognized that the problem was repetitive in nature, a clear understanding of the root cause was sought and a technically sound, thorough approach to the problems was carried through to completion.

The licensee's actions, troubleshooting efforts and diagnostic tests were reported in Calvert Cliffs Event Report 86-02, which presented a comprehensive and detailed consolidation of all aspects of the feed water system problems and associated problems contributing to or aggravating the situation. Root causes were identified for each problem, and recommended specific corrective action for prevention in the future. Implementation of these recommendations should alleviate this kind of feed water system problems in the future.

The apparent delay in, or slow recognition of, the causally linked plant trips appears to be caused by the lack of tangible proof or data which the licensee attempts to obtain before a thorough investigation is initiated. The NRC position regarding plant trips is that a clear understanding of the root cause should be determined and the cause corrected prior to restart. The licensee's action was, in this case, untimely.

### Reactor Coolant Pump Vibration

During the preceding several months, Reactor Operators have been periodically responding to "Reactor Coolant Pump Vibration" annunciator alarms. Investigation by the operator revealed that the installed four (4) Bentley Nevada vibration instruments on Unit 1 were indicating the typical 8 to 18 mils, depending on which pump. Based on this, a Maintenance Request was submitted to investigate the cause of the alarm. In April vibration signatures were recorded for all RCP's utilizing the installed Bentley Nevada (BN) probes together with more sensitive portable instruments. These signatures revealed that RCP-12A was displaying unusual subharmonic peaks at about 1/3 to 2/3 running speed (885 RPM). These subharmonic peaks varied in amplitude initially from 1-10 mils whereas the overall gross vibration for RCP-12A was a nominal 8-11 mils, (RCP 11A-18 mils, RCP 11B-13.5 mils, RCP 12B-10 mils).

During April the licensee continued to monitor the 12A vibration and solicited advice from industry sources i.e. (Babcock and Wilcox, Byron Jackson, Nuclear Power Reliability and BN) regarding the subharmonic frequencies. Although no final conclusions were reached, it was generally thought that the cause might be due to an internal rub, (i.e. hydrostatic bearing or low motor bearing). The information received from the above industry sources indicated that subharmonics are not a significant parameter characteristic of shaft cracking, however there is apparently no case history of subharmonics in RCP shafts.

On May 5 it was noted that the subharmonics appeared to be increasing in amplitude. The licensee obtained a Bentley Nevada representative on site with more sophisticated (BN 7200 Series RVXY-II) instrumentation capable of determining peak to peak amplitude, radial shaft vibration, key phase signal and pulse (orbitals), and filtered and unfiltered recording of each of the above. During May 5-8 the subharmonics increased and a shift in the phase angle was noted with the new instrumentation.

The licensee intensified their efforts and concerns. Continuous monitoring of vibration was conducted and operators were briefed to be particularly aware of unusual RCP seal characteristics. Action level criteria were placed in the Operators Night Orders should the vibration worsen. Plans were formalized to commence a plant outage on May 17 based upon the increasing subharmonic trend. RCP-12A gross vibration remained lowest of the RCP's for both units. On May 12, RCP 12A subharmonics returned to their original level (less than 10 mils) and have remained at that level.

On May 13 the licensee compiled a lesson plan/report on: causes of vibration, characteristics of vibration, complex vibration and phase interrelationship, Bentley Nevada Equipment, steps to take when monitoring outputs, and recording data. The report was presented to senior

reactor operators and operations staff personnel. Acceptable operating criteria and changes that should be reported are called out. Operators were cautioned to be alert for changing vibration or RCP seal parameters.

The licensee has ordered a RCP impeller, and a RCP shaft is being prepared i.e., balanced for a planned investigation/overhaul and inspection of 12A RCP during the upcoming refueling outage and 10 year ISI inspection in the fall of 1986.

The licensee has previously determined that the Calvert Cliffs RCP shafts are dissimilar to those shafts that have recently been identified to have cracking due to intergranular stress corrosion in that Calvert Cliffs RCP shafts are (1) cooled by a different mechanism (no seal injection - less thermal stress) and (2) shaft material is different (stainless 304 vs ASTM A286). The licensee believes that there is only a very low probability that shaft cracking is a possible problem.

The licensee's action regarding this event appears to date to be appropriate.

No violations were identified.

#### 4. Observation of Physical Security

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

No violations were identified.

#### 5. 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 on site follow up. The following LER's were reviewed.

<u>LER No.</u>	<u>Event Date</u>	<u>Report Date</u>	<u>Subject</u>
<u>Unit 1</u>			
*85-11	09-30-85	10-29-85	Main Steam Safety Valve Setpoints Out of Specification
*86-02	03-22-86	04-21-86	Inadvertent Closing of Shutdown Cooling Return Valve
86-03	04-30-86	05-29-86	Battery Water Level Exceeded High Level Limit
<u>Unit 2</u>			
*86-04	05-21-86	06-19-86	Manual and Automatic Reactor Trips on Low Steam Generator Water Level

\*Detailed examinations of these events are documented in routine resident inspection reports.

No inadequacies were identified

#### 6. 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 controls for worker protection, fire protection, retest requirements, and reportability per Technical Specifications. The following activities were included.

- Follow up maintenance associated with the Feed Water Control problems described in the Operations paragraph including (a) 4517 Pressure Differential Indicating Controller Replacement and (b) inspection of wiring and terminal boards associated with Feed Water pump controls.
- Auxiliary Feed Water Pump inspection, oil change and sample PM-2-36-M-M-2.
- Replacement of Main Steam Isolation Valve Hydraulic Bladders.
- Repacking No. 11 and 12 Auxiliary Feed pump packing glands.

No violations were identified.

## 7. 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-0-8-B-1, 12 EDG and 4KV Bus 14 LOCI Sequence Test.
- STP-0-5-2, Auxiliary Feed Water System Test.
- STP-0-7-2, Engineering Safety Features Monthly Logic Test.
- STP-0-62-2, Monthly Valve Position Verification
- STP-0-87-1, Borated Water Source Operability Verification.
- STP-M-210B-2, RPS Functional Test.
- STP-M-225-1, AFAS Functional Test.
- STP-M-77-0, Staggered Test of Diesel Fire Pump.

No violations were identified.

## 8. Survey of Licensee Response to Selected Safety Issues

Temporary Instruction 2515/77 was sent to Resident Inspectors to ascertain whether specific safety issues identified and disseminated by various industry information systems were being adequately addressed by licensees or whether additional NRC action would be required.

Concerns specific to Pressurized Water Reactors regarding Bio-fouling of Cooling Water Heat Exchanger, and Natural Circulation Cool Down are addressed below.

### Regarding Bio-fouling

The Service Water, Emergency Core Cooling Pump Room and Component Cooling Heat Exchangers are the only safety related components subject to bio-fouling. Fire protection systems utilize a closed fresh water system, and are not subject to bio-fouling. These components are instrumented with temperature, pressure differential, and/or pressure instrumentation. Periodic, i.e., either hourly or shift readings are logged on Auxiliary Operator log sheets which include acceptance criteria for required action. Use of these instruments are included in OI-29, Salt Water System and a Performance Evaluation 1-12-6-0-W which occurs weekly where an evaluation is performed and preventative maintenance takes place if necessitated. These PM's are routinely observed by the inspectors. Frequency of bio-cleaning of the Heat Exchangers varies with seasonal changes. Discussion with operators and review of system

description revealed that training does not discuss operator actions if significant heat exchanger performance degradation is detected as a result of bio-fouling. However, on the job training by Shift Supervisors of their own volition does instruct Auxiliary Operators in the appropriate action.

#### Natural Circulation Cool Down

Natural Circulation Cool Down is addressed in both Emergency and Abnormal Operating Procedures (EOP and AOP). Abnormal Operating Procedure AOP-3F "Natural Circulation Cool Down" is the basic document for this concern. It describes actions to be taken when unexplained level increases occur in the pressurizer; when and how to place let down and make up controls in manual during periods of anomalous pressurizer level indications and references the use of the saturation monitor instrumentation or use of the ASME Steam Tables and various temperature indicators to ensure reactor coolant inventory is being maintained. Abnormal Operation Procedure AOP-2A "Excessive Reactor Coolant Leakage" and Emergency Operating Procedure EOP-8 "Functional Recovery Procedure" both provide guidelines on what actions should be taken to ensure reactor coolant inventory when pressurizer level indication is in question/suspected of being inaccurate. AOP-3F also discusses how to avoid steam void formation in the head area, and provides clearly defined plant conditions to be met before a reactor coolant pump can be restarted following a planned or inadvertent pump trip.

In addition to the above, Unit 2 has installed the Reactor Vessel Water Level Monitoring Instrumentation (RVWLM) required by NUREG 0737 IIF2(3.b). Procedures for the operation of the unit are implemented, however procedures for when to use the device are still under development. Unit 1 RVWLM is due to be installed during the up coming refueling outage scheduled for October 1986.

This information was forwarded to the NRC Region I coordinator for this TI.

No violation were identified.

#### 9. Radiological Controls

Radiological controls were observed on a routine basis during the reporting period. Standard industry radiological work practices, conformance to radiological control procedures and 10 CFR Part 20 requirements were observed. Independent surveys of radiological boundaries and random surveys of non-radiological points throughout the facility were taken by the inspector.

-- During the report period three anonymous telephone calls were received by the inspector alleging that: (1) three personnel had "jimmied" the door to the Unit-2 twenty seven foot west penetration room, a High Radiation Area, (2) that copies of keys to high radiation area locked doors were maintained by numerous people throughout the facility and that the keys to the key locker containing High Radiation Area Keys were uncontrolled. This information received on April 22 and 24, 1986 was immediately reported to the NRC Region I Office (Allegation RI-86-A-0045).



Subsequent follow up by the inspector revealed that on April 17, 1986, two Instrument and Control (I&C) technicians had been assigned to calibrate a transmitter within the Unit-2 five foot west penetration room. The technicians were briefed by the Radiation Control Shift Supervisor (RCSS) and signed into the controlled area under the appropriate Special Work Permit (RWP) 86-003A and adhered to the requirements of the RWP (i.e., maintained proper dosimetry, dress, processed a PIC6A exposure rate meter, etc.) except that the individuals did not check in with the health physics (HP) technician (who possessed the key to the High Radiation Area). Instead, the I&C personnel used a screwdriver and "jimmied" the door to the west penetration room. The HP technician had been previously notified by the RCSS of the impending job. At the time he was occupied with routine surveying while awaiting the arrival of the I&C technicians. While passing the five foot west penetration room after completing daily surveys, the HP technician noted personnel within the five foot west penetration room and realized that they had entered the High Radiation Area without his briefing or consent. The HP technician immediately escorted the individuals to the control point for discussion with the Radiological Controls Supervisor. The Supervisor counseled/discussed the incident with the employees and dismissed them without further action. This information was documented in the HP technicians log of April 17, 1986. This forced entry into a locked High Radiation Area constitutes a Licensee Identified Violation of the Special Work Permit in that the Instrument and Control technicians failed to contact the HP technician as required under item V of SWP 86003A.

On May 6, 1986, a third anonymous call was received by the inspector reaffirming that keys to High Radiation Areas remained uncontrolled. To further illustrate this, the inspector was made aware of the location of two uncontrolled keys. The Operations Manager, the inspector and the Radiological Control Supervisor together verified that these keys provided access to all locked High Radiation Areas on site. Further, the inspector pointed out that the key to a key box which contained additional High Radiation Area keys was left uncontrolled during back shifts in the Radiological Controls Shift Supervisor's unlocked desk. The allegor considered this to be commonly known.

This additional information was provided to NRC regional staff. As a result, on May 6 a telephone conversation between Mr. Tiernan of Baltimore Gas and Electric and Mr. Wenzinger of NRC occurred regarding the above issues. On May 7, a follow up letter was sent to Baltimore Gas and Electric reiterating the NRC's understanding of the licensee's planned investigation, possible corrective actions and schedule for completion.

On June 6, 1986, the licensee formally replied to the identified concerns stating the following corrective action:

### "Forced Entry into a Locked High Radiation Area

Door guards (metal plates) have been installed to help prevent unauthorized access. This was completed May 9, 1986.

The Supervisor-Radiation Control Operations counseled the individuals, and Radiation Control Reports were issued April 17, 1986, to document the incident for their Supervisors' response. In addition, their Supervisor formally counseled the individuals involved.

A note was placed in the Shift Supervisors' Night Orders by the General Supervisor-Operations on April 25, 1986, to increase operator attention to locked high radiation areas.

Although the individuals involved did force their way into a high radiation area, they met all other requirements to enter (Work Permit, proper dosimetry, rate meter, etc.).

### Existence of Unauthorized Copies of Keys to Normally Locked High Radiation Areas

Locks for all high radiation areas which are required to be locked in accordance with the Technical Specifications, were replaced on May 8, 1986, with an industrial grade security lock and key system (routinely non-reproducible).

Radiation Safety personnel were instructed on May 8, 1986, to maintain personal possession of high radiation keys and the keys to the key storage locker.

### Overall Management Concerns to Address Issues 1 and 2 Above

The "Nuclear Hotline" was previously established as a phone number for anonymous individuals to call to report items of concern.

The Manager-Nuclear Operations briefed all onsite employees on May 29, 1986, on the incidents. He reminded them of the company policy for reporting items of regulatory concern and the availability of the "Nuclear Hotline".

In addition to the above, the Radiation Safety Section was briefed on both incidents and they were instructed on the policy for communicating regulatory items of concern to company management."

Technical Specification 6.12.1 High Radiation Area requires that keys to High Radiation Area barricades be controlled and maintained under the separate administrative control of the Supervisor-Radiation Control and the Operations Shift Supervisor.

Contrary to the above, on May 6, 1986, two keys to all locked High Radiation Area barricades were found by the inspector. These particular keys were neither maintained or under the administrative control of the Supervisor-Radiation Control or the Operations Shift Supervisor. This is a violation (317/86-09-01;318/86-09-01).

-- Radiological Environmental Monitoring Program

The inspector reviewed the licensee's Radiological Environmental Monitoring Program annual report for 1985. This report summarizes the results of the sampling and analyses of environmental media to determine the radiological impact of station operations. These environmental media include air, water, vegetation, and aquatic plants and animals. In addition, direct radiation is monitored by placement of thermoluminescent dosimeters at various locations around the station.

As a result of this review, the inspector determined that the licensee has generally complied with its Technical Specification requirements for sampling frequencies, types of measurements, analytical sensitivities, and reporting schedules. The report included summaries of the laboratory quality assurance program and of the land use survey. The analyses of environmental samples indicated that doses to humans from radionuclides of station origin were negligible.

No inadequacies were identified.

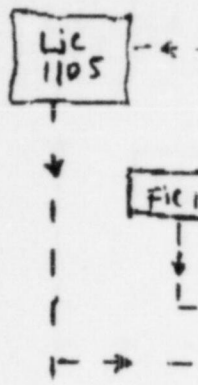
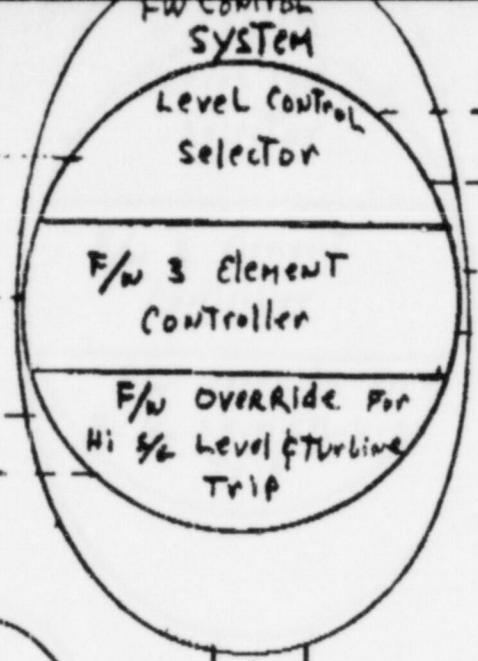
10. Review of Periodic and Special Reports

Periodic and special reports submitted to the NRC pursuant to Technical Specification 6.9.1 and 6.9.2 were reviewed. The review ascertained: inclusion of information required by the NRC; test results and/or supporting information; consistency with design predictions and performance specifications; adequacy of planned corrective action for resolution of problems; determination whether any information should be classified as an abnormal occurrence; and validity of reported information. The following periodic reports were reviewed:

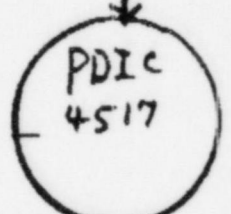
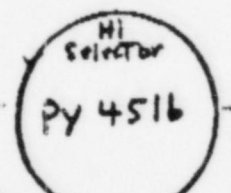
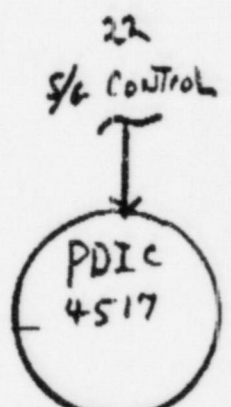
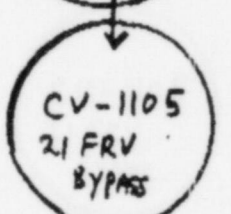
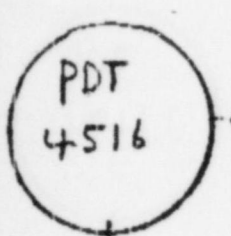
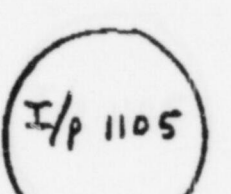
- April, 1986 Operations Status Reports for Calvert Cliffs No. 1 Unit and Calvert Cliffs No. 2 Unit, dated May 9, 1986.
- May, 1986 Operations Status Reports for Calvert Cliffs No. 1 Unit and Calvert Cliffs No. 2 Unit, dated June 10, 1986.

11. Exit Interview

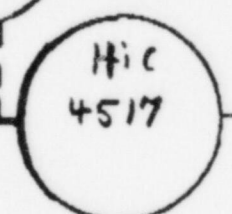
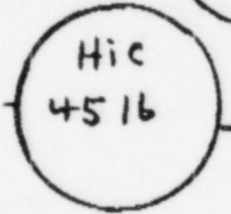
Meetings were periodically held with senior facility management to discuss the inspection scope and findings. A summary of findings was presented to the licensee at the end of the inspection.



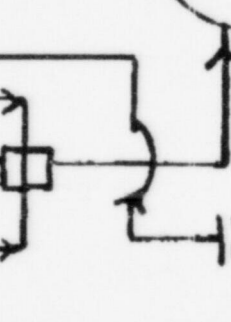
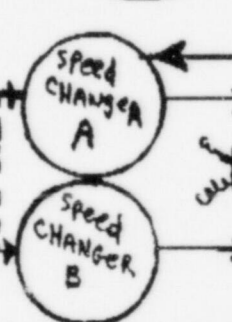
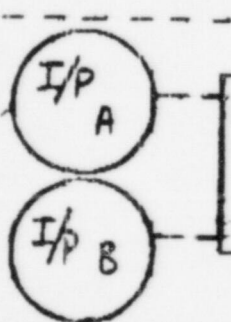
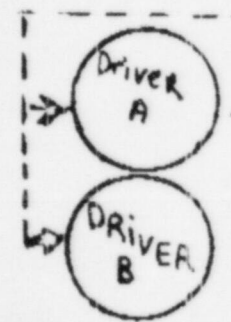
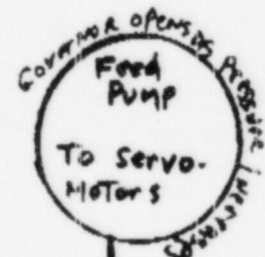
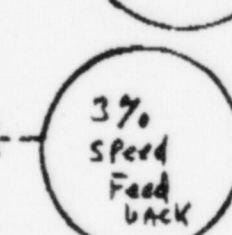
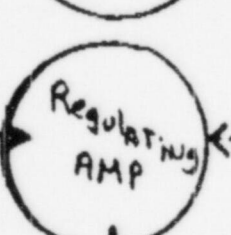
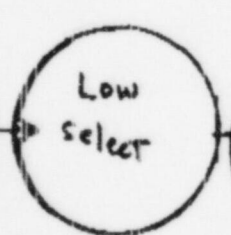
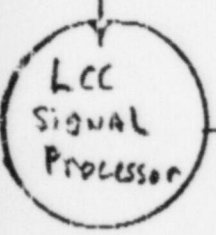
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21 SGFP speed Control



To 22 SGFP controls



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