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U. S. NUCLEAR REGULATORY COMMISSION
Region I

Docket/Report: 50-317/83-30 License: DPR-53
50-318/83-30 DPR-69

Licensee: Baltimore Gas and Electric Company

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

Inspection At: Lusby, Maryland

Dates: October 11-November 15, 1983

Submitted:

for T. C. Elsasser
R. E. Architzel, Sr. Resident Inspector — 12/1/83 date

for T. C. Elsasser
D. C. Trimble, Resident Inspector — 12/1/83 date

Approved:

T. C. Elsasser
T. Elsasser, Acting Chief, Reactor Projects Section 1A — 12/1/83 date

Summary:
October 11-November 15, 1983: Inspection Report 50-317/83-30, 50-318/83-30. Areas Inspected: Routine resident inspection (145 hours) of the control room, accessible parts of plant structures, plant operations, radiation protection, physical security, fire protection, plant operating records, maintenance, surveillance, radioactive effluent sampling program, open items, TMI Action Plan items, refueling activities, and reports to the NRC. No violations were identified.

DETAILS

1. Persons Contacted

The following technical and supervisory personnel were contacted:

M. E. Bowman, Principal Engineer, Incore Fuel Management
D. E. Buffington, Fire Protection Inspector
J. T. Carroll, General Supervisor, Operations
S. E. Cherry, Principal Chemistry Technician
P. T. Crinigan, General Supervisor, Chemistry
J. A. Crunkleton, Supervisor, Electrical Maintenance
R. E. Denton General Supervisor, Training/Technical Services
C. L. Dunkerly, Shift Supervisor
A. Ensor, Assistant General Foreman, PMD
T. Forgette, Supervisor, Emergency Planning
J. E. Gilbert, Shift Supervisor
J. F. Lohr, Shift Supervisor
J. A. Mihalcik, Principal Engineer, Fuel Cycle Management
N. L. Millis, General Supervisor, Radiation Safety
J. M. Moreira, General Supervisor, Electrical & Controls
J. E. Rivera, Shift Supervisor
L. B. Russell, Plant Superintendent
J. A. Snyder, Supervisor, Instrument Maintenance Unit 2
R. W. Talley, Jr., Assistant General Foreman, PMD
J. A. Tiernan, Manager, Nuclear Power Department
A. M. Voggel, Radiation Safety Engineer
R. L. Wenderlich, Supervisor, Operations Quality Assurance, Auditing
D. F. Zyriek, Shift Supervisor

Other licensee employees were also contacted.

2. Licensee Action on Previous Inspection Findings

(Closed) Non-Compliance Items (318/80-02-01 and 318/80-02-09) Radioactive Material Release Path Created by Open CVCS Ion Exchanger Vents During Reactor Coolant Ion Exchanger Resin Transfers. OI-17C (Revision 18 dated August 31, 1983), Section XXXI, no longer requires opening of the Chemical and Volume Control System (CVCS) ion exchanger vents during resin transfers from the Reactor Coolant ion exchangers. The radioactive material release path of concern has thus been eliminated.

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

--On October 19, 1983, the inspector noted that the Control Room temperature indicator for the East Piping Penetration Room (2TI5275) was pegged high, reading greater than 150°F. The inspector pointed this out to the Control Room Operator. The operator wiggled the electrical cabling to the indicator, and temperature indication varied widely indicating a loose connection. A Maintenance Request was initiated.

--During Control Room checks on October 25, 1983, the inspector questioned the Unit 2 Control Room Operator regarding the status of several key lock switches. The switches for the Channel A and B Safety Injection Actuation System (SIAS) Block and the Electropneumatic Relief Valve (ERV) Block Valves had their keys installed in the switches. The switches were in the correct position for the plant operating condition (SIAS block in normal, ERV block valves open). Review of the Control Room Key Control file revealed that these keys were not signed out in the logsheet, however, a metal tag indicating that the keys were in the handswitch were in the locker's appropriate key holders. The inspector discussed the licensee's Key Control System with the Operations Key Custodian. The Custodian (a Shift Supervisor) stated that Operations keys which were to be used in the Control Room, in the sight of the Senior Control Room Operator, did not need to be signed out in the key logsheet. The Custodian further stated that a key remained in a key switch or back in the key locker at the discretion of the Senior Control Room Operator. (Some keys are captive in certain positions and must remain in the switch.) The inspector noted that placement of the keys in the switches could in effect change the function of a switch from administrative controls to simply another switch. The licensee also audits the keys at 6 month intervals (last audit performed on August 3, 1983). The inspector discussed key control with the General Supervisor-Operations, noting that the methodology being used to administratively control keys in the Control Room was not consistent with that specified in CCI-110, Key and Lock Control. The GS-O stated that their controls would be reviewed and the CCI/controls appropriately changed to ensure consistent administrative control of these switches. This item is unresolved (318/83-30-01).

No unacceptable conditions were identified.

b. Weekly 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 inspections of major components were performed. Operability of instruments essential to system performance was assessed. The following systems were checked:

--Fuel Oil Storage System checked on October 17, 1983.

--Locked Valves in Unit 2 Containment checked on October 17, 1983.

--Containment Isolation Valve Lineup in Unit 2 27' West Piping Penetration Room checked on October 19, 1983.

--Unit 1 Containment Purge System checked on October 14, 1983.

--Containment Penetration Valves in the Unit 2 27' East Piping Penetration Room checked on October 28, 1983.

No unacceptable conditions were identified.

c. Biweekly Inspection

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 tagouts indicated the action was properly conducted.

--Tagout #1858, #12 Saltwater System checked on October 18, 1983.

--Tagout #1513, Unit 2 Containment Purge Valves checked on October 28, 1983.

Records and sample results of the following activities were reviewed to verify conformance with regulatory requirements.

--G-168-83, Unit 1 Main Vent Gas Release resulting from escaping Radiogas from vicinity of Degasifier Vacuum Pump, released on October 28, 1983.

--G-169-83, Unit 2 Main Vent Gas Release from escaping Radiogas from vicinity of Degasifier Vacuum Pump, released on October 28, 1983.

--R-167-83, #12 Reactor Coolant Waste Monitor Tank and Main Waste Monitor Tank, released on October 14, 1983.

--The Unit's 1 and 2 Steam Generator Logs, Reactor Coolant Logs, Refueling and Spent Fuel Pool, CVCS, and Safety Injection Chemistry Logs, and the Chemistry Smooth Log were reviewed for the week of October 17, 1983.

No unacceptable conditions were identified.

d. Other Checks

--Two Radiological Events were declared on October 28, 1983 due to escaping radiogas from the degasifier vacuum pumps while venting pump accumulator reference legs. The first event was declared at 2:30 a.m. when the Unit 1 Main Vent Gaseous Monitor readings increased. The second event was declared at 5:30 a.m. when the Unit 2 Main Vent Gaseous Monitor readings increased. The licensee calculated an activity release for the 2:30 a.m. event of 3.48% of the Technical Specification (T.S.) instantaneous release rate limit for gross activity. The second release was calculated to be 8.6% of the above limit.

The inspector reviewed Technical Support Procedure 138, Unit 1 Pressurizer Transmitter Pressure Testing and Flushing, reviewed by the Plant Operations and Safety Review Committee and approved October 7, 1983. This procedure was complete and thorough regarding valving arrangements, flushing requirements, and hydrostatic testing precautions. It did not address required plant conditions nor appropriately caution regarding the effects of raising the pressure sensed by the transmitter. The Shift Supervisor who approved the testing did recognize that the Pressure instrument which initiates a Safety Injection signal would have to be opened but did not recognize the need to defeat the SDC supply valve interlock. The inspector noted the above procedural inadequacy and failure to properly establish plant conditions for the test to the licensee on October 10, 1983. An incident review had been undertaken by the Operational Safety and Licensing unit to assess the event and propose corrective actions. The inspector stated that he would review the analysis and proposed actions to assess their adequacy. As of the end of the reporting period the licensee's investigation of this event had not been completed. This item will be followed (317/83-30-01).

--At 12:10 a.m. on October 14, 1983, a normal radioactive liquid discharge from the #12 Reactor Coolant Waste Monitor Tank (RCWMT) was secured after operations personnel realized that, during the discharge, about 1500 gallons of additional radioactive liquid (53000 gallons total discharged) had been pumped into the RCWMT. The additional liquid had not been properly sampled and accounted for in the existing release permit. Post release calculations showed that the additional water effectively diluted the liquid waste authorized by the existing, approved permit and a composite sample of the actual discharge was obtained so that the release was conservatively monitored and within limits. The inspector reviewed Liquid Waste Permit R-167-83 authorizing the release of #12 RCWMT and documenting the unplanned, monitored release of the MWMT. This permit showed activity to be within limits (2.2 E-2 curies total, 1.4 E-4 curies contributed from the MWMT). The unplanned release of the MWMT was discovered by the Unit 2 Control Room Operator who noted the decreasing level of the tank during a turnover walkdown of the Control Room Panels. The Auxiliary Building Operator knew that the RCWMT was being discharged, however, was apparently confused by a recent memorandum from the Chemistry Group. This memorandum, dated September 30, 1983, stated that during the Unit 1 outage the MWMT was to be pumped directly to the #12 RCWMT without sampling or recirculating which had been the previous practice. In addition, the Operating Instruction did not have any procedural restriction against pumping the MWMT to the RCWMT. Additional information surrounding this event is contained in Inspection Report 317/83-29;318/83-29).

--Unit 2 tripped from full power at 12:40 p.m. on October 26, 1983, following the loss of the operating Electro-Hydraulic Control (EHC) pump, causing all turbine valves to close. The pump was lost when a pressure switch lead was inadvertently shorted during a Planned Maintenance (PM) activity. I&C technicians were performing PM 2-93-IR-3 which calibrates

the EHC pressure switches. During the testing of the pump pressure switch which starts the standby pump the leads for both pumps are lifted to prevent sending a start signal to the pumps. The shorted lead tripped the operating EHC pump and the standby pump did not start because of its lifted lead. The licensee stated that this PM, required at 18 month intervals, would be changed to a refueling PM to preclude similar events.

The inspector reviewed post trip data and observed licensee actions in the Control Room. Immediately prior to the trip Cold Leg Reactor Coolant System temperature reached 563° F, exceeding the DNB parameter (548° F). The reactor tripped from low Steam Generator levels. Main and Auxiliary Feedwater were used to restore levels to normal. Pressurizer pressure reached about 2400 psia, with the Power Operated Relief Valves opening to limit the pressure. Steam Generator pressure, which was limited by the Safety Valves, reached a maximum of 1030 psia.

The inspector went to the Technical Support Center to examine parameters following the trip, however the Computer was not operable at the time. The licensee had discovered (after the trip) that the TSC Computer was not updating and had apparently stopped functioning at 1:15 p.m. on October 23, 1983 due to a probable software deficiency. The condition was not annunciated in the TSC or the Control Room, which have provisions for monitoring the Computer's status. The licensee obtained a memory dump, which was sent offsite to try to find the problem. Resolution of the software deficiency will be followed by the NRC (318/83-30-02).

--A Unit 2 plant trip from full power occurred at 11:41 a.m. on October 11, 1983 when the #22 Main Feedwater (MFW) Pump steam admission valves shut causing a low level in both Steam Generators (SG). Following the plant trip, #21 Feedwater Regulating valve failed to close as designed, the valve failed in the 60% open position. As a result #21 SG went off scale high and the Reactor Coolant System was overcooled (lowest temperature reached was 510°F, vs 532°F normal temperature following a trip). Safety Injection initiated (setpoint greater than 1725 psia). The lowest pressure reached was 1660 psia, which is above the discharge pressure of the High Pressure Safety Injection pumps (about 1250 psia). The Turbine Bypass valve was locally isolated and charging pumps restored Pressurizer level. The cooldown was terminated as soon as feedwater was stopped to #21 SG by isolation of the Main Feedwater system by operators. Plant conditions were stabilized in Hot Standby, with the licensee investigating the event and equipment malfunctions.

Following the plant trip increased Reactor Coolant System leakage was noted from #21A Reactor Coolant pump vapor seal. The increased leakage was noted by an increase in Containment sump pumping frequency, and may have been caused by stopping and then restarting the Reactor Coolant pump during the event. A plant cooldown was commenced on October 12, 1983 to repair the seal leakage.

A Radiological Event was declared at 2:40 p.m. on November 6, 1983, when the Unit 2 Main Vent Monitor readings increased. The licensee found that the #21 Vacuum Degasifier pump seal water accumulator had emptied allowing gas from a Waste Gas Decay Tank to leak past the degasifier pump seal. The Radiological Event was terminated at 3:20 p.m. The licensee calculated (Abnormal Radioactive Release Permit G-175) the activity release to be 12% of the T.S. instantaneous release rate limit for gross activity.

--At 9:50 p.m. on October 27, 1983, with Unit 2 operating in Mode 1, a small fire occurred in lagging on piping beneath the High Pressure turbine. The cause of the fire was oil dripping onto hot pipe lagging. The Fire Brigade removed lagging from the pipe and extinguished the fire. The inspector discussed the event with the station Fire Protection Inspector and visited the scene of the fire. The licensee stopped the oil leak and cleaned other piping in the area to reduce the possibility of any future fire.

--With Unit 2 operating at 70% power, at 8:50 p.m. on October 19, 1983 CEA 46 (a Shutdown Group control rod) dropped into the core. Control Room personnel carried out proper recovery actions and restored the CEA to its proper full out position. The event was caused by a water leak in the Control Room head. The water seeped through the floor and onto the power supply cabinet for CEA 46 in the Cable Spreading Room. The leakage path was later identified to be a cable penetration beneath the Security Computer in the Control Room. The leakage path was sealed with "flamastic" material.

No unacceptable conditions were identified.

4. Review of Events Requiring One Hour Notification to the NRC

The circumstances surrounding the following events requiring prompt NRC (one hour) notification per 10CFR50.72 via the dedicated telephone (ENS-line) were reviewed.

--Shutdown Cooling (SDC) was lost at 7:40 p.m. on October 12, 1983, when the Reactor Coolant System (RCS) Hot Leg supply valves to SDC shut on an inadvertent high pressure signal. Unit 1 was in the Refueling Mode at the time with a vent path. RCS temperature was initially at 115°F, and level was being maintained half way up the RCS Hot Leg. The cause of the isolation was a hydrostatic test being performed on the Pressurizer Pressure Instruments without prior disabling of the SDC valve isolation function (not needed with a vent path). SDC flow was reestablished in 40 minutes following removal of the hydrostatic test pressure. Automatic closure of the SDC supply valves was subsequently defeated by jumpering the high pressure signal. The initial peak SDC inlet temperature was 195°F, however, temperature rapidly equalized at 130°F with the SDC flow. No increase in Containment radioactivity was observed due to the possible boiling in the vessel.

The licensee determined the cause of the #22 MFW pump trip to be leakage in the control oil system. The #21 Main Feedwater Regulating valve remained open due to air relay failures in the upper valve positioner. The #21 MFW pump speed controller is designed to maintain constant MFW Regulating valve differential pressure. Because the #21 Main Feedwater Regulating valve remained open the #21 MFW pump continued to run as designed at high speed to maintain valve differential pressure. The Turbine Bypass valve remained open due to mechanical binding.

Upon initiation of the Safety Injection Actuation signal the #22 Low Pressure Safety Injection (LPSI) pump started as designed. The pump was stopped by operations personnel after the Safety Injection Actuation System was reset. A start failure alarm was then received in the Control Room for the #22 LPSI pump. The pump could not be restarted. Troubleshooting revealed that a breaker shutter interlock switch was not properly made up. This prevented the charging motor from recharging the pump breaker closing spring. The interlock switch was adjusted and the pump tested.

The licensee has initiated a Licensee Event Report (LER) for this event. The NRC will review that LER upon issuance.

--An inadvertent actuation of the Steam Generator Isolation System (SGIS) occurred on Unit 1 at 10:46 a.m. on November 12, 1983. The actuation happened in Mode 6 (refueling) during the conduct of a modification verification test. Technical Support Procedure 140, Trip Test of CSAS NB-3 and SGIS A/B-1, approved November 7, 1983, was written to test the Main Feed train trip function which was installed to satisfy the IE Bulletin 80-04 reanalysis. Prior to testing the trip feature the procedure directed that the SGIS setpoints be lowered by first lowering the trips, then lowering the blocks. The engineer performing the test erred by first lowering the trip on Channel A, then lowering the Channel B block, followed by lowering the trip and Channel B block such that the actuation occurred when the second SGIS sensor block was lowered (2 of 4 logic for the trip, 3 of 4 logic for the block). The engineer stated that this had just been a mental lapse, noting that he had successfully performed the same post modification test on Unit 2. Because this was a one time test, no long term corrective action was deemed to be necessary.

--At 3:15 p.m. on November 1, 1983 with Unit 1 in Mode 6 (refueling), a partial Engineered Safety Features Actuation System (ESFAS) actuation occurred during the reenergization of B Logic cabinet following maintenance on #12 120VAC instrument bus. Only part of the Containment Spray Actuation System (CSAS) actuated (one Containment Cooler fan started and one cooler Service Water valve opened). Other components receiving CSAS signals were out-of-service.

ESFAS sensor cabinet ZE, which is powered by Instrument Bus #12, was deenergized at the time and, therefore, was sending a trip signal to the B logic cabinet. An erroneous trip signal, not shown on an indicator panel, from a second sensor cabinet (due to a bad signal isolation device) was also being sent to the B logic cabinet. Therefore, when the logic cabinet was energized, the 2 out of 4 trip logic was satisfied. The isolator problem was corrected by the licensee.

--During a Unit 2 startup, between 1:15 and 1:20 p.m. on October 19, 1983, Pressurizer level dropped below the TS operating band lower limit of 133 inches (lowest level was 130 inches). The level problem occurred immediately after the main turbine was paralleled to the grid and was due to overcooling the Reactor Coolant System (RCS) when the turbine picked up a load of about 40 MW. The turbine had operated as designed (it is designed to pickup an adjustable amount load following a paralleling operation). Following the event the licensee adjusted the turbine control system to pickup a smaller amount of load during paralleling operations to minimize overcooling of the RCS.

No unacceptable conditions were identified.

5. Observation of Physical Security

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

No unacceptable conditions were identified.

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

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

LER No.	Event Date	Report Date	Subject
Unit 1			
83-50	9/12/83	10/12/83	#12 Hydrogen Analyzer Inoperable
83-51	9/27/83	10/18/83	#12 Diesel Generator Inoperable
83-52	8/10/83	10/05/83	Oyster Samples Collected during August, 1983 showed Ag-110m to be 118±8 pCi/kg (wet)

83-53	9/21/83	10/20/83	Charcoal Filter Bypass Damper for Spent Fuel Pool Ventilation System would not shut completely
83-54	9/28/83	10/28/83	TH Input to Channel "C" Reactor Protection System Trip Units for Power Level, Axial Flux Offset and Thermal Margin/Low Pressure Failed
83-55	10/01/83	10/25/83	Three Main Steam Safety Valves did not Lift at Required Setpoint
83-56	10/07/83	10/26/83	Heat Damaged Snubber Discovered on Piping between Pressurizer and a Code Safety Valve
83-57	10/10/83	11/09/83	Cracked Weld on Instrument Stop Valve for #11B LPSI Flow Transmitter
83-58	10/04/83	11/03/83	Load Shed of #12 SRW Pump Inoperable
83-59	10/11/83	11/10/83	CVCS Isolation Signal for Channel ZF Inoperable
83-60	10/05/83	11/03/83	Fire Door between #11 Emergency DG Room and #12 Emergency DG Room Removed for Modification Work
83-61	10/12/83	11/01/83	Shutdown Cooling Return Isolation Valves were Shut Terminating Shutdown Cooling*
Unit 2			
83-49	9/09/83	10/07/83	Pin Hole Leak in Reactor Coolant Charging Line Weld
83-50	9/22/83	10/13/83	Main Steam Valve to Steam Driven AFW Pumps Inoperable
83-51	9/01/83	9/27/83	Following Reactor Trip Dose Equivalent I-131 was 1.05 Micro-Curies Per Gram
83-52	9/23/83	10/21/83	AFW Pump Inoperable*
83-53	9/14/83	10/07/83	Fuse Replacement Blew Causing 21 Containment Cooler to Trip

83-54	10/11/83	11/10/83	#21 Main Feedwater Regulating Valve Inoperable
83-55	09/20/83	10/20/83	Pressurizer Level Decreased Below 133 Inches Twice
83-56	10/11/83	11/10/83	#22 LPSI Pump Inoperable*
83-58	10/18/83	11/08/83	During RCS Heatup Dissolved Oxygen Concentration was 1.0 PPM in Excess of Transient Limit
83-59	10/11/83	11/10/83	Dose Equivalent I-131 was 1.03 Micro-Curies Per Gram

*LER's followed up on site described elsewhere in this report.

No unacceptable conditions were found.

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

--MR #O-83-7652, Troubleshoot #22 LPSI Pump observed on November 7, 1983.

--MR #83-2334, Install #22 HPSI Pump, work started on August 8, 1983.

--MR #GEN-6, Pump Maintenance Procedure and FT-M-3, Coupling Alignment Test, included as attachments, observed on October 28, 1983.

--During the observation of the installation of #22 HPSI pump the mechanics encountered difficulty aligning the suction and discharge piping. The MR was revised to allow adjustment of hangers to ease the installation of the bolts. Following extension of the rods on a discharge piping spring hanger, the mechanics were able to bolt up the flange, using considerable force with a lever to align the flange. A similar effort was required for the suction piping. No measurements of the amount of cold pipe springing were made to allow determination of pipe/casing stresses. The inspector discussed this point with the licensee engineer responsible for pump installation, commenting that cold piping springing should be determined to be within allowable limits for an installation of this nature. The licensee subsequently decided to adjust the hangers on the

pump suction and discharge lines. Following adjustments the pipe to pump flange bolts could be inserted without springing the piping. Alignment readings were determined to be within the manufacturer's specifications before and after connecting the suction and discharge lines.

No unacceptable conditions were identified.

8. 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:

--Fuel Inspection performed in Spent Fuel Pool Inspection Elevator using Underwater Periscope in accordance with Procedure FH-39, Revision 0, observed on October 28, 1983.

--STP #M-512-1 Incore Instrument Calibration observed on November 10, 1983.

No unacceptable conditions were identified.

9. Unit 1 Cycle 7 Refueling Activities

Prior to the start of the Unit 2 refueling the inspector reviewed the following Operating Instructions and and Fuel Handling Procedures:

--OI-25E, Fuel Transfer System, approved September 7, 1983.

--OI-25B, New Fuel Elevator, approved September 7, 1983.

--OI-25A, Spent Fuel Handling Machine, approved September 7, 1983.

--FH-6, Unit 1 Cycle 7 Fuel Handling Procedure, approved October 12, 1983.

--OI-25C, Refueling Machine, approved September 7, 1983.

--OI-25D, CEA Change Machine, approved September 7, 1983.

The inspector observed fuel movements during several shifts, examined records of Machine testing, and watched portions of the Fuel Inspections being performed to measure fuel pin gaps.

The inspector noted that Containment Integrity was being maintained as required during core alterations. Good housekeeping practices were being followed in the refueling pool area, including material accountability over the pool. The licensee's staffing was observed to be in accordance with the Technical Specifications during refueling.

On November 9, 1983, the inspector observed the preparations for the placement of the Unit 1 Reactor vessel head back on the vessel following refueling.

--During a Unit 1 Control Element Assembly (CEA) uncoupling evolution early on October 15, 1983, a small bolt (1.5 inches long, ¼ inches in diameter) and its nut were found missing from the CEA uncoupling tool. The licensee was concerned that the nut and bolt could possibly have fallen into the Reactor vessel. The CEA's were being uncoupled in preparation for refueling. The licensee conducted an extensive search but could not locate the nut and bolt. The licensee assessed the consequences of these loose items in the Reactor Coolant System during operation and determined that no Steam Generator damage would be expected. In the worst case only minor fuel pin damage would result from fretting (at most could cause 10 fuel pins to leak which would result in iodine levels corresponding to 30% of the Technical Specification limit). The Plant Operations and Safety Review Committee reviewed and concurred with this assessment on November 11, 1983.

No unacceptable conditions 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.

--TAP II.B.1 (2) and (3) Reactor Coolant Vent System (RCVS). This item updates information previously discussed in Section 8 of Inspection Report 50-317/82-05, 50-318/82-05 dated April 16, 1982. On September 7, 1982, the NRC issued a Safety Evaluation (SE) for the licensee's RCVS for both units. The RCVS consists of two vent paths (one from the Pressurizer and one from the Reactor vessel) each containing two manual valves and two solenoid valves in series. The solenoid valves are operated from the Control Room. Both paths direct vent flow to the Quench Tank. The Quench Tank can then be vented to either the Containment atmosphere (through a new solenoid valve) or to the Waste Gas System. After installation, the Unit 1 solenoid valves were stroke tested in December, 1980 and the Unit 2 valves were similarly tested in March, 1981. Each unit's RCVS was then disabled by lifting leads to the five solenoid valves pending NRC review and approval. Valve position indication circuits were left intact. The inspector noted that in the interim the two manual valves (2PS-149 and 150) in the Unit 2 Pressurizer vent path had been maintained shut (these valves are located inside the Containment building). All other vent path manual valves had been maintained open. During a Unit 2 Cold Shutdown for

repair of a Reactor Coolant Pump seal which began on October 11, 1983, the licensee opened manual valves 2PS-149 and 150. Additionally, during the shutdown, the licensee stroke tested the Unit 2 solenoid valves to comply with the requirements of subsection IWV of ASME Code Section XI for Category B valves.

The inspector reviewed the RCVS Operating Instruction OI-1G, Revision 1, dated June 29, 1983, and noted that the Senior Control Room Operator's instruction binder contained both the current edition of OI-1G and the previous edition, Revision 0. This discrepancy was pointed out to the Acting General Supervisor-Operations, who stated that this would be corrected. Additional procedural guidance on use of the system will be developed based upon guidelines being generated by the Combustion Engineering Owners Group in response to NUREG 0737 requirement I.C.1., "Guidance for the Evaluation and Development of Procedures for Transients and Accidents".

This item remains open pending further NRC inspection.

11. Review of Periodic and Special Reports

Upon receipt, periodic and special reports submitted pursuant to Technical Specification 6.9.1 and 6.9.2 were reviewed. That review included the following: Inclusion of information required by the NRC, test results and/or supporting information, consistency with design predictions and performance specifications, planned corrective action adequacy 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:

--September, 1983 Operations Status Reports for Calvert Cliffs No. 1 Unit and Calvert Cliffs No. 2 Unit, dated October 14, 1983.

No unacceptable conditions were identified.

12. Unresolved Items

Unresolved items require more information to determine their acceptability and are discussed in Details 3.a and 4.

13. 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. No written material has been provided to the licensee during the preparation of this report.