DCS Nos.	50317831002	50318830802	50318830303	50320792903
	831202	831102	830903	
	830703	831802		
	831103			

U. S. NUCLEAR REGULATORY COMMISSION
Region I

Docket/Report: 50-317/83-07 License: DPR-53
50-318/83-07 DPR-69

Licensee: Baltimore Gas and Electric Company

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

Inspection At: Lusby, Maryland

Dates: March 15 - April 12, 1983

Submitted:

for D N Johnson 4/15/83
R. E. Architzel, Sr. Resident Inspector date

for D N Johnson 4/15/83
D. C. Trimble, Resident Inspector date

Approved:

for D N Johnson 4/18/83
E. C. McCabe, Jr., Chief, Reactor date
Projects Section 2B

Summary:
March 15 - April 12, 1983: Inspection Report 50-317/83-07, 50-318/83-07. Areas Inspected: Routine resident inspection (153 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, Emergency Planning Exercise, IE Bulletins, Dose Calculation Model Comparisons, 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, Nuclear Fuel Management
D. E. Buffington, Fire Protection Inspector
J. T. Carroll, General Supervisor, Operations
J. A. Crunkleton, Supervisor, Electrical Maintenance
C. L. Dunkerly, Shift Supervisor
A. Ensor, Assistant General Foreman, PMD
J. E. Gilbert, Shift Supervisor
J. F. Lohr, Shift Supervisor
R. O. Mathews, Assistant General Supervisor, Nuclear Security
N. L. Millis, General Supervisor, Radiation Safety
J. M. Moreira, General Supervisor, Electrical & Controls
G. S. Pavis, Engineer, Operations
J. E. Rivera, Shift Supervisor
L. B. Russell, Plant Superintendent
L. Smialek, Senior Plant Health Physicist
J. A. Tiernan, Manager, Nuclear Power Department
R. L. Wenderlich, Engineer, Operations
D. F. Zyriek, Shift Supervisor

Other licensee employees were also contacted.

2. Licensee Action on Previous Inspection Findings

(Closed) Inspector Follow Item (317/83-05-02) Review of Licensee's Calculation of Proper Main Feedwater Bypass Valve Setting. On March 25, 1983, the inspector completed a review of the licensee's preliminary calculation (the calculation was still under licensee review) of Main Feedwater bypass valve setting. The licensee used two hydraulic flow equations described in the ISA (Instrument Society of America) Handbook of Control Valves, 2nd Edition. The inspector reviewed applicable parts of the above handbook and confirmed that the equations used by the licensee were appropriate to this application. One equation, hereafter referred to as equation 1, was used in conjunction with an industry standard flow curve (for a control valve with "equal percentage" valve position versus flow characteristics), valve manufacturer data, and expected valve differential pressure following a Reactor trip, to verify that the Main Feedwater flow through the valve at the original setpoint (33% valve open position) would be less than 5% of full flow. A second equation was used in conjunction with equation 1 to calculate choke flow through the valve in a main steam line break situation (maximum differential pressure across the valve) at the original setpoint position. The choke flow was also determined to be less than 5% of full Main Feedwater flow. The inspector checked selected portions of the licensee's calculations to confirm they were mathematically correct. The licensee stated that the valve setpoint will not be adjusted above the original setpoint (33% open position). The licensee informed the inspector that the make and model of the control valves were physically verified in the plant to ensure that the correct valve data was being used in the calculations. This item is closed.

(Open) Unresolved Item (317/83-02-01) Reanalysis of the Main Steam Line Break (MSLB) Analysis Which Would Include the Effects of Operation of the Auxiliary Feedwater (AFW) System as an Initial Condition. On March 22, 1983, the Plant Superintendent committed to minimize the use of the Unit 1 Auxiliary Feedwater System in Modes 1,2, and 3 during non-transient or non-accident situations until the system is modified to include an automatic function for blocking AFW flow to an affected Steam Generator during a MSLB (presently the modification is scheduled for the Fall 1983 Unit 1 Refueling Outage). In the event the AFW system must be used in Modes 1,2, or 3 non-transient/non-emergency situations, the Plant Superintendent committed to station a dedicated operator, near the Unit 1 AFW system controls, who is trained to take necessary AFW control actions in the event of a MSLB. During the week of March 7, 1983, the licensee informed the inspector that they had performed an analysis for the MSLB which showed that, with the automatic AFW blocking feature installed and with AFW running at the beginning of the accident, acceptable results were obtained for peak Containment pressure and Return-To-Power. The licensee stated that this accident analysis would be submitted to the NRC for review. This item will remain open pending licensee submittal of this analysis.

(Closed) Unresolved Item (317/82-26-03) Revise Emergency Procedures to Adequately Address Spills of Radioactive Liquid. The licensee has revised Emergency Response Plan Implementation Procedure 3.6, Radiological Event, to clarify that any large, uncontrolled spill of radioactive liquid constitutes a Radiological Event. Previous revisions of the Emergency Response Plan Implementing Procedures had only addressed spills of Reactor Coolant.

(Closed) Inspector Follow Item (317/82-29-01) Control Element Assemblies (CEA's) Inserted in Core Below the Upper Computer Stop Resulting in Simultaneous Outward Motion of All CEA±s. A caution note has been placed adjacent to the Raise/Hold/Lower Switch on the Main Control Board for both units to warn operators that raising CEA's when the groups are below the Upper Computer Stop will result in simultaneous outward motion of all CEA's. Preventative Maintenance Procedure PM-81-1-0-M requiring positioning of CEDM's below the Upper Computer Stop has been cancelled.

(Open) Inspector Follow Items (318/83-02-03) Revise Technical Specification 3.1.3.3 to clarify requirements for action in the event one of the Control Element Assembly (CEA) position indication systems is inoperable. The licensee has submitted proposed Technical Specification changes to clarify action in the event that one CEA position indication channel is inoperable. The NRC Licensing Project Manager discussed the proposed changes with the inspector and requested that the inspector examine Facility Change Requests (FCR's) which had been initiated following the recent inoperablity of the position indication for CEA #44 on Unit 2 and CEA #28 on Unit 1. The inspector reviewed the Safety Analyses for FCR's 83-05 for Unit 2 and 83-09 for Unit 1. The Safety Analyses in question were thorough and complete. Initially, the Unit 2 FCR had required that CEA #44 (a shutdown bank CEA) be fully withdrawn at which time power leads to the CEA lift coil would be lifted to prevent CEA motion, thus creating a CEA motion inhibit (CMI) type condition. In addition, a 10 volt DC signal (equivalent to CEA full out signal) was required to be inserted into the CMI logic. These actions allowed CMI to be operable for the regulating group rods. When CEA #28 was discovered to have inoperable position indication on Unit 1, a Facility Change Request was initiated which required the simulated full withdrawn signal to be switched through an interposing relay off the core memory display upper electrical limit indication. This change resulted in a CMI being operable for any motion with the CEA with an inoperable position indication and the required difference in position for other CEA's in the group. The inspector had no further questions regarding the Facility Change Requests. This item remains open pending completion of review and issuance of Technical Specification changes.

(Closed) Violation (317/82-30-03) Temporary Shielding Installation. During the inspection period, the inspector reviewed the licensee's March 10, 1983, response to the subject violation. The information contained in the response was consistent with the corrective actions previously noted by the inspector and reported in Inspection Report 317/83-05, 318/83-05. The licensee has now implemented adequate administrative controls on temporary shielding.

(Closed) Violation (317/82-26-05) Inoperability of the Hydrogen Purge System. The licensee responded to this violation in letters dated November 16, 1982, and December 17, 1982, and stated that:

(1) They recognize the requirements of and intend to comply with 10CFR50.59;

(2) The blind flange was removed from the replacement air blower discharge (Unit 1);

(3) A checklist for making revisions has been added to the governing instruction for the Calvert Cliffs Operating Manual (CCOM) which includes the Final Safety Analysis Report (FSAR) and 10CFR50.59 and will alert the licensee to proposed CCOM changes which might be inconsistent with the requirements of the Final Safety Analysis Report or 10CFR50.59; and

(4) Should they later decide to retire the Hydrogen Purge System, the Responsible Design Organization will perform an analysis of the effect of flanging the replacement air blowers, report the results of the analysis to the NRC as required by 10CFR50.59, and revise the FSAR.

The inspector confirmed that the blind flange had been removed from the Unit 1 replacement air blower discharge and that, during December 1982, the Unit 2 replacement air blower discharge had been checked open. The inspector reviewed Calvert Cliffs Instruction (CCI) 300F, "Calvert Cliffs Operating Manual", through change 5 dated January 27, 1983. Section V of CCI 300F now requires that procedure revisions be reviewed against 10CFR50.59 to determine if the revision involves an unreviewed safety question. Plant procedures may be changed through two administrative mechanisms - a "change" or a "revision". Since CCI 300F only addressed "revisions" relative to 10CFR50.59, the inspector examined CCI 101H to determine if procedure "changes" receive a 10CFR50.59 review. CCI 101H requires, in Section V.B.2, that "changes" (to those plant procedures which have previously been reviewed by the Plant Operations and Safety Review Committee [POSRC]) be reviewed by the POSRC within fourteen days of implementation. CCI 103, "Organization and Operation of the Plant Operations and Safety Review Committee", Revision F dated March 15, 1983, requires the POSRC to make a determination, for the procedure "changes" it reviews, whether or not an unreviewed safety question exists as defined in 10CFR50.59. Technical Specification (TS) 6.8.3 permits the licensee to make temporary changes to the procedures referenced in TS 6.8.1 provided the original intent of the procedure is not altered, the change is approved by two members of the plant management staff (at least one of whom holds a Senior Reactor Operator's license), and the change is reviewed by the POSRC and approved by the Plant Superintendent within 14 days of implementation. Based on the above review, the inspector concluded that the licensee now has in place adequate controls to ensure that both "changes" and " revisions" to plant procedures for which the POSRC has review responsibility will be reviewed against 10CFR50.59 for unreviewed safety questions.

(Closed) Inspector Follow Item (317/83-05-01) Licensee Provide Appropriate Guidance to Operations Personnel Regarding Proper Pump Alignment to Redundant Power Supplies. This item related to a problem noted in the pump lineup for two Unit 1 Component Cooling Water (CCW) pumps. The General Supervisor, Operations (GS-O) discussed the particular CCW pump problem noted by the inspector with each Shift Supervisor and is currently discussing it with all Operations Group sections on a rotational basis. To date all personnel with whom the GS-O has held discussions have indicated a satisfactory awareness of the proper pump alignment to redundant power supplies. The GS-O intends to continue his discussions until all operations sections are reached. Because the problem noted by the inspector was apparently an isolated case, the personnel involved were made aware of the problem and all operations sections will be counseled on the subject, this is being adequately addressed by the licensee and is closed.

(Closed) Unresolved Item (317/83-05-03) Offsite Safety Review Committee (OSSRC) Responsibility For Verifying That Facility Changes Do Not Involve Unreviewed Safety Questions. On April 11, 1983, the inspector discussed this item with the Chairman of the OSSRC. The OSSRC Chairman assured the inspector that he and the other members of the OSSRC were cognizant of their responsibility to verify that Facility Changes do not involve unreviewed safety questions as defined in 10CFR50.59. The Chairman acknowledged that he had unconsciously erred on March 14, 1983, in asking the OSSRC to determine, for reviewed Facility Changes, whether the changes would result in an undue risk to the health and safety of the public rather than whether an unreviewed safety question existed. The inspector had no further questions. This item is closed.

3. Review of Plant Operations

a. Daily Inspectionn

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. These checks were performed on the following dates: March 15, 17, 18, 22, 23, 24, 28, 29, 31, April 5, 7, and 8, 1983.

--On April 5, 1983, the inspector noted that two ladders were obstructing access to a CO2 fire extinguisher and a Halon System Manual Trip Station in the Unit 2 Cable Spreading Room. The inspector pointed out these obstructions to the Shift Supervisor, who stated they would be moved.

b. Weekly System Alignment Inspection

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

--Diesel Generator Air Start System checked on March 28, 1983.

--Unit 2 High Pressure Safety Injection System inspected on March 29 and March 30, 1983.*

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

During lineup checks on March 30, 1983, the inspector pointed out to the station Fire Protection Inspector that a vertical fire barrier between safety related cable trays (ZF2AE77 and ZGZAE73) in the 45 foot elevation Unit 2 West Electrical Penetration Room was broken and missing. The cable trays were approximately one foot apart (three foot separation between tray ZG2AE73 and the nearest exposed cable in tray ZF2AE77). On March 31, 1983, the inspector noted to the Fire Protection Inspector that in the same penetration room the horizontal fire barrier separating safety related cable trays ZB2AE76 and ZF2A77 (the trays had a vertical separation of about three feet) was broken or missing in several places. Section 8.5.5 of the Updated Final Safety Analysis Report states that:

"A minimum of 3 feet horizontal separation is maintained or physical fire barriers are installed between trays. Where a barrier is required, it extends to a minimum of 1 foot above and below the cable tray or to the ceiling or floor, or it completely encloses each cable tray of one separation group.

Where the vertical stacking of redundant cable trays is unavoidable, a minimum spacing of 5 feet is maintained, or horizontal fire barriers are installed between trays, or each cable tray of one separation group is completely enclosed with a fire barrier."

The Fire Protection Inspector stated, in both cases, that the type of material used for these fire barriers is easily broken and the maintenance of those barriers is a continuing problem. The Fire Protection Inspector stated that he would initiate action to have the barriers repaired on a high priority basis. On April 1, 1983, the inspector reviewed the licensee's "Interactive Cable Analysis for Unit 2", dated February 1, 1982, and noted that it does not rely on the integrity of the above fire barriers for safe plant shutdown capability (for 10CFR50, Appendix R, Section III G requirements) in the event of a fire in this penetration room. Restoration of the above fire barriers will be reviewed by the NRC during a future inspection (317/83-07-01).

c. Biweekly Inspection

Verification of the following tagouts indicated the action was properly conducted.

--Tagout 2509, No. 12 Salt Water Pump dated March 22, 1983, reviewed on March 24, 1983.

--Tagout 71448, No. 22 High Pressure Safety Injection Pump dated October 27, 1979, reviewed on March 30, 1983.

--Tagout 718, Unit 2 Safety Injection Tank Outlet Valves dated January 8, 1983, checked on March 30, 1983.

--Tagout 2432, #12 Diesel Generator Air Compressor, checked on March 28, 1983.

Boric acid tank samples were compared to the Technical Specifications. Tank levels were also confirmed.

While reviewing instrumentation calibration records for the Unit 2 High Pressure Safety Injection System (HPSI), the inspector noted that a discharge pressure switch (2 PS-301Z) for the No. 23 HPSI pump was not included in the Planned Maintenance (PM) program for calibration checks and no records were on file which would indicate calibration checks had been completed on this switch. The pressure switch is used for a Control Room alarm annunciator function only. Calibration checks have been accomplished on the related pressure transmitter (2-PT-301Z). The inspector informed the technician in charge of the Planned Maintenance program of the above omission. Further checking by the technician showed that the counterpart pressure switches for HPSI pumps 21 and 22 (2-PS-301X and 2-PS-301Y) were similarly not included in the PM program. The inspector recommended inclusion of these pressure switches in the program. On April 8, 1983, the technician in charge of the PM program told the inspector that the above pressure switches have been added to a PM program change currently in progress. The inspector had no further questions.

e. Other Checks

During plant tours, the inspector observed shift turnovers, security practices within protected and vital areas, the use of radiation work permits, and Health Physics procedures. Area radiation and air monitor use and operational status was reviewed. Plant housekeeping and cleanliness were evaluated.

--On March 29, 1983, the inspector noted that a "step-off" pad outside the door to the Unit 2 five foot elevation Penetration Room was immersed in a puddle of water. The Penetration Room was posted as a contaminated area, and the puddle of water extended from the "step-off" pad toward the room entrance. The "step-off" pad, therefore, could no longer serve the function of identifying where the contaminated area ended. The inspector discussed the problem with the on-duty Health Physics Technician who indicated he would initiate corrective action.

--On March 29, 1983, the inspector noted that the door to the Unit 2 five foot elevation East Piping Penetration Room was blocked open by scaffolding and could not be closed without disassembling a part of the scaffolding. Since a blocked open door can degrade the capability of the Penetration Room Ventilation System to meet its design objective of maintaining a negative pressure in the penetration rooms, the inspector discussed the situation with the Shift Supervisor and asked that the scaffolding be moved to permit door closure. The Shift Supervisor said that he would initiate corrective action.

--During the review of Change No. 10 to Calvert Cliffs Instruction 104-F, Surveillance Test Program, the inspector noted that the licensee had established a two-tier system for actions to be taken if a valve stroke time exceeds its specified (ASME Section XI) acceptance criteria. If the valve stroke time exceeds an action acceptance criteria established by the Technical Specifications it would be declared inoperable and the applicable Technical Specifications referred to. If the valve stroke time exceeds an action acceptance criteria not dictated by Technical Specifications, then the GS-O determines the operability of the valve. Discussions with the GS-O determined that the action level stroke times for valves not specifically addressed in the Technical Specifications had been arrived at on a somewhat arbitrary basis, however, the times, as determined, would require the initiation of corrective action to improve valve stroke time. The inspector questioned whether valves whose stroke times are essential during anticipated transients and accidents may not be properly identified as inoperable because the associated times are not specifically addressed in the Technical Specifications. The GS-O stated that stroke times for valves in this category had been determined based upon required response times. He further stated that a review of the valves in this category would be performed, and that the Calvert Cliffs Instruction would be revised for the valves in question to indicate that the acceptance criteria was specified by the Technical Specifications. This item is unresolved (317/83-07-02)

4. Radioactive Waste Management

Records and sample results of the following radioactive waste releases were reviewed to verify conformance with regulatory requirements prior to release.

--Liquid Waste Tank Release Permit M-037-83, March 22, 1983, Release of Miscellaneous Waste Monitor Tank, reviewed on March 23, 1983.

--Gaseous Waste Permit G-030-83, March 22, 1983, Release of Decay Tank #11, reviewed on March 23, 1983.

A spill of radioactive resin and water occurred about 10 p.m. on March 28, 1983, when a sight glass broke during resin transfer operations. The resin and water were confined to the areas surrounding the spent resin metering tank (inside the Auxiliary Building) and the building floor drains. No gaseous or liquid releases occurred. An operator was slightly contaminated when he entered the area to investigate. The inspector discussed the event with licensee personnel and reviewed records of surveys and the licensee's plans for decontamination of the spent resin metering tank area. The sight glass apparently broke following transfer of the resin in the Miscellaneous Waste Ion Exchanger, which processes floor drains and other low level wastes. An operator had been stationed at the sight glass observing resin flow during the transfer operation. The line had subsequently been flushed with demineralized water and attempts were made to dewater the line using pressurized nitrogen as required by OI 17-D, Miscellaneous Waste Processing Systems. The operators were unable to build-up any pressure in the spent resin metering tank due to the broken sight glass. Upon investigating the resin transfer lineup the operator noticed water and resins coming out from under the Spent Resin Metering Tank Room Door. The operator was contaminated when he entered the area to investigate the source and secure the lineup. The on-shift Health Physics Technician surveyed and posted the area. Complete survey results on March 29, 1983, indicated resin as deep as two inches with readings between 20 to 400 mrem immediately above the resin on the floor.

The inspector questioned the licensee concerning why a Radiological Event had not been declared for this spill. Emergency Response Plan Implementing Procedure 3.6, Radiological Event, requires that a Radiological Event be declared, if evaluation indicates, for any large, uncontrolled spill. The Radiological Event category is intended to provide a mechanism to allow assessment of conditions below the thresholds of the Emergency action Levels specified in the Emergency Plan. The Shift Supervisor stated that he felt that this spill was controlled at the time of discovery, and did not meet the criteria for a Radiological Event. In addition, he stated that the Health Physics Technician was the interim Radiation Assessment Director and had arrived at the scene prior to himself. Because the spill was terminated and the area isolated no additional actions would have been initiated by declaring a Radiological Event. The inspector agreed that the wording of the Emergency Response Plan Implementing Procedure was vague in this area, however, a conservative interpretation would have been that 1 to 2 cubic feet of resin sprayed all over the resin metering tank room and on the floor was a large, uncontrolled spill. The Auxiliary Building Operator also noted to the inspector that the bulls-eye sight glass used on the spent resin transfer line had been cracked for several months prior to breakage. An MR had been initiated, however, the sight glass had not been repaired due to inability to obtain replacement parts. The licensee initiated Calvert Cliffs Event Report 83-09 to evaluate the event and propose corrective action to prevent similar events. The inspector noted that this event could have had very serious radiological consequences if this sight glass had broken when Reactor Coolant Waste Processing Resin was being transferred through the line with an operator present. Licensee resolution of the problems identified, to be addressed in Calvert Cliffs Event Report 83-09, and the decontamination of the spent resin metering tank room will be followed by the NRC (317/83-07-03).

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.

Two bomb threats were received during this reporting period. The required security procedures were followed. Appropriate searches were conducted with negative results. No violations were identified.

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

a. 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			
83-09	2/10/83	3/10/83	Snubber 2-15-10 not included in U2 T.S. and STP's.
83-11	2/12/83	3/10/83	RWT level decreased below the limit of T.S. 3.5.4.a
83-13	3/07/83	4/06/83	Hydrogen Analyzer 0-AE-6519 Inoperable
83-14	3/11/83	4/08/83	No. 12 Charging Pump Inoperable when No. 13 Charging Pump isolated to correct packing leak

LER No.	Event Date	Report Date	Subject
Unit 2			
83-10	2/08/83	3/10/83	AFAS Channel ZF Setpoint for Steam Generator delta pressure out of specification
83-12	2/11/83	3/11/83	Twice during past 30 days, dose equivalent I-131 exceeded 1.0 micro-Ci/gram
83-16	3/03/83	3/24/83	#21 Diesel Generator Inoperable
83-17	2/18/83	3/17/83	#21 Saltwater Loop Inoperable
83-18	3/03/83	3/31/83	HPSI Header Inoperable
83-19	3/09/83	3/31/83	CEA Motion Inhibit Inoperable

b. For the LER's selected for onsite review, the inspector verified that appropriate corrective action was taken or responsibility assigned and that continued operation of the facility was conducted in accordance with Technical Specifications and did not constitute an unreviewed safety question as defined in 10 CFR 50.59. Report accuracy, compliance with current reporting requirements and applicability to other site systems and components were also reviewed.

--Unit 1/82-13 and Unit 2/82-42. These LER's described problems with No. 13 Charging Pump relief valve, 1-RV-326, sticking open. These LER's did not provide sufficient detail on planned corrective actions for the inspector to assess whether or not those actions appeared adequate. On April 11, 1983, the inspector discussed this problem with the Unit 1 Assistant General Foreman (AGF) for the Production Maintenance Department. The AGF stated that the relief valve had exhibited a tendency to stick open when two Charging Pumps were already running and the third Charging Pump was started. The AGF further stated that the relief valve setpoint had been raised on 1-RV-326 and 1-RV-325 (No. 12 Charging Pump relief) from 2735 psig to 2800 psig about March 8, 1983. The setpoint for 1-RV-324 (No. 11 Charging Pump relief) will also be increased at a later date. The AGF stated that Facility Change Request (FCR) 81-124 had evaluated this setpoint increase, and that the setpoint increase should prevent recurrence. The inspector reviewed FCR 81-124 and noted that it also applied to the Unit 2 Charging Pump relief valves (2-RV-324, 325, and 326). The FCR reevaluated the design pressure of "CC-7" piping downstream of the Charging Pumps and changed the pipe rating from 2735 psig to 2835 psig. The FCR contained calculations supporting a Charging Pump relief valve setting of 2800 psig. The FCR evaluation methodology appeared to be adequate. The licensee had performed on evaluation for FCR 81-124, which was reviewed by the POSRC and which concluded that no unreviewed safety question was involved, as required by 10CFR50.59. The AGF told the inspector that since the setpoint for 1-RV-326 has been raised, the relief valve lifting problem has not recurred. The inspector had no further questions.

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-E83-94 (Unit 1) and MR-E83-93 (Unit 2), observed initial testing of undervoltage trip function for the Reactor trip circuit breakers (required by IE Bulletin 83-04) on March 15, 1983.

--MR-E83-97 (Unit 1) and MR-E83-98 (Unit 2), observed follow on testing of undervoltage trip function for the Reactor trip circuit breakers (IE Bulletin 83-04) on March 16, 1983.

--MR-E83-102 (Unit 1) and MR-E83-103 (Unit 2), observed portions of corrective maintenance performed on Reactor Trip Circuit Breakers on March 17, 1983.

--MR-M-83-130, Remove and inspect Intake Check Valve on #11 Diesel Generator, observed on April 6, 1983.

--MR-0-83-3067, observed preparations for corrective maintenance on the Unit 2 No. 22 Salt Water Pump on April 18,1983.

During inspection of the intake air check valve on #11 DG, the licensee found that one of the two pins holding the check valve in place on its shaft was sheared and the check valve was loose. The check valve was being inspected because similar valves on the other two diesel generators had been found to be cracked when inspected during 1982. The disks of one of these valves was found to be broken into two pieces. The licensee stated that these failures did not render the diesel generators inoperable, therefore, no Licensee Event Reports had been issued. The licensee pointed out that there were internal baffles between the check valves and the diesel turbo-charger which made it unlikely to have a piece of the check valve (aluminum disk) enter the diesel's turbo-charger. The check valve in question diverts air between the diesel turbo-charger and air blower. Failure of the check valve would result in air being directed through the turbo-charger at low lines. The circumstances surrounding the failures will be reviewed by the NRC for generic implications.

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:

--M-210B-2, Unit 2 Reactor Protection System Functional Test, observed on April 5, 1983.

--STP M-225-2, Auxiliary Feedwater System Functional Test, observed on April 11, 1983.

No unacceptable conditions were identified.

9. Emergency Response Exercises

On March 16, 1983, and March 22, 1983, the licensee conducted Emergency Planning Exercises simulating a large steam line break outside Containment (concurrent with primary-to-secondary steam generator tube leakage) caused by a seismic event. The March 16 exercise was directed at testing the response of the onsite emergency organization. The March 22 exercise was directed at testing the response of the recovery organization and the dose assessment/offsite monitoring organization. During the exercises, phone communications with outside agencies were tested. The inspector observed both drills and attended the post-exercise critique for the March 16, 1983 exercise. The inspector observed the First Aid team and activities in the Control Room, the Operational Support Center, Emergency Control Center, and the Alternate Emergency Control Center. All levels of licensee management personnel participated in at least one exercise including the Vice President, Supply, the Vice President, Engineering and Construction, the Manager, Nuclear Power Department, and the Plant Superintendent. During the critique observed by the inspector (March 16) problem areas noted by observers, evaluators, and participants were candidly pointed out. The inspector noted no major deficiencies.

On March 16, 1983, the inspector learned that immediately prior to the March 15, 1983, licensee Emergency Plan Exercise at least one group of workmen was told to assemble for a safety meeting. Additionally, the inspector learned that the plant page cannot be heard by workers in some areas of the plant. Therefore, the inspector was concerned that these workers were essentially readied for the subsequent plant evacuation (i.e., tools put away and personnel assembled in an area where they could hear the plant page), and that any measured evacuation time would not be accurate.

On March 17, 1983, the inspector mentioned this concern to the licensee's Plant Superintendent and the Manager of the Nuclear Power Department for their information, and said he would discuss it further with the Emergency Planning Supervisor. On March 18, 1983, the inspector discussed this concern with the Emergency Planning Supervisor who stated that:

(1) He would contact appropriate management personnel and ask that safety meetings not be scheduled in this matter so that more representative drills can be run;

(2) An engineering study is underway to correct problems with the plant page so that it can be heard in all areas (currently an NRC open item in the Emergency Planning area); and

(3) Although the licensee has quarterly drills, the capability of getting people to go to assembly areas is only required to be done annually (in other words this aspect of emergency planning only needs to be accurately assessed once per year).

During the inspection period the inspector noted that the Emergency Planning Supervisor, by memorandum, had requested that safety meetings not be scheduled in the manner described above. The licensee appears to be taking adequate corrective action in this area. The inspector had no further questions.

10. Licensee Actions Following Plant Trips

On March 23 and 25, 1983, the inspector reviewed the types of computer information available to plant staff personnel following reactor trips and the licensee's practices in obtaining and reviewing/analyzing this information. Following is a list of information available to the licensee from the Plant and the Technical Support Center Computers in a post reactor trip situation:

(1) Plant computer alarm printout (printer is located at the Control Room Operator's desk for each unit; depending upon the parameter, sample times range from once per second to once per minute);

(2) Plant Computer Sequence of Events Program which samples selected system contacts and provides an accurate indication of sequence of equipment trips (prints out on the Control Board CRT or on the utility printer located in front of each Control Room Operator's desk);

(3) Plant Computer Post Trip Review which provides a record of pre-selected parameters for a period of five minutes before and after a plant trip (data recorded at 30 second or 2 second intervals, depending on the parameter; prints out on demand on the in-core printer in the Control Room); and

(4) the Technical Support Center Computer post trip data which records selected data before and after the trip at 1 second intervals and is available on demand in the Technical Support Center/Computer Room area adjacent to the Control Room.

The Plant Computer Alarm and Sequence of Event printouts include parameter descriptions which make them "user friendly". A licensed operator told the inspector that operations personnel have little difficulty understanding and using these two printouts. Idiosyncrasies associated with data handling and display on the Plant Computer Alarm printout can interject slight time distortions so that, in some cases, events may be logged out of correct sequence. The Plant Computer Post Trip Review printout is not as "user friendly". Data is printed out using point identification numbers instead of parameter descriptions. Data points are not conveniently time labeled, and the user must count backwards or forward from a reference time to determine precise time of occurrence for individual data points. Discussions with two licensed operators indicated that the operators are less familiar with the Plant Computer Post Trip Review printout. The Technical Support Center Computer Post Trip data report does more clearly couple data points to time labels, but, again, data points have point identifiers instead of descriptive labels. Until recently, operations personnel required computer technician support to obtain a Technical Support Center computer printout. On March 17, 1983, a procedure was provided to the operators for obtaining this printout.

Emergency Operating Procedure (EOP) 1, "Reactor Trip", Revision 11 dated April 7, 1982, requires the recall of the post trip review on the utility typewriter. The post trip review prints out on the in-core printer. The Sequence of Events program prints out on the utility typewriter. The terminology problem caused confusion in the mind of one operator during a discussion with the inspector. The procedure does not clearly indicate what program the operator should demand. The inspector pointed out this procedural inadequacy to the Acting General Supervisor, Operations (GSO), who stated that he believed the intent of the procedure was to call up the

Sequence of Events program. He also stated that a procedure change is under preparation which would require the recall of both the Sequence of Events and Post Trip Review Computer information following reactor trips and that EOP 1 will be clarified. Later inspection confirmed that the Sequence of Events Printout is automatically printed by the utility typewriter. Correction of the above procedure inadequacy will be reviewed during a future inspection (317/83-07-04).

As of March 15, 1983, the licensee did not have in place any specific administrative requirements to review or analyze computer trip data. The licensee does, however, require through GS-O Standing Instruction 82-1, "Post Incident Critique", that meetings be held following unscheduled Reactor Trips to collect information regarding the event.

On March 15, 1983, the Plant Superintendent stated the following regarding current licensee practices and planned actions for post Reactor Trip situations:

(1) A change will be issued to EOP 1 which more clearly specifies who can authorize plant restart following Reactor Trips and under what conditions;

(2) Currently, meetings are held following Reactor Trips (the licensee is attempting to hold these meeting within two hours of the trip) with key supervisory, operations, and maintenance personnel to review the trip, initiate any needed further investigations, determine necessary maintenance/repairs, review Technical Specification requirements, and determine the path to restart;

(3) A Calvert Cliffs Instruction to require the meetings discussed in item number (2) above is under preparation; and

(4) Significant events (such as those that may involve unreviewed safety questions) are reviewed by the safety committees as required by the Technical Specifications.

The above information was obtained for NRC use in evaluating the adequacy of licensee practices in reviewing post Reactor trip information. On March 28, 1983, the inspector recommended to the Plant Superintendent that the following actions be taken relative to post reactor trip reviews:

(1) Develop a post trip review procedure;

(2) Assure that adequate reviews of plant charts and data be conducted before restart;

(3) Assure that the above reviews include review and analysis of plant computer data by personnel who understand the computer printouts;

(4) Assure that responsibilities are assigned for a subsequent verification that the initial analysis is correct;

(5) The Plant Operations and Safety Review Committee should evaluate all Reactor trip events for potential safety hazards (The committee should determine the extent of these evaluations);

(6) For certain Reactor trip events, the Plant Operations and Safety Review Committee evaluation should be conducted prior to plant restart (The committee should develop appropriate criteria for determining which events should be evaluated prior to restart and the extent of the evaluation); and

(7) Clarify the role of the Offsite Safety Review Committee in evaluating Reactor trip events (The committee should develop any necessary criteria for determining which events should be evaluated, the timing of these evaluations, and the extent of the evaluations).

Licensee implementation of the above recommended actions will be reviewed during a future inspection (317/83-07-05).

11. IE Bulletin Followup

The inspector reviewed licensee actions on the following IE Bulletins to determine that the written response was submitted within the required time period, that the response included the information required including adequate corrective action commitments, and that licensee management had forwarded copies of the response to responsible onsite management. The review included discussions with licensee personnel and observations and review of items discussed below.

--IE Bulletin 83-04 "Failure of the Undervoltage (UV) Trip Function of Reactor Trip Breakers". This bulletin described recent failures of General Electric AK-2 breakers used in the Reactor Protection System (RPS) at San Onofre, Units 2 and 3. The bulletin requested licensees with other than Westinghouse DB type breakers to perform specific actions to assure proper operation of these breakers in the future. The licensee has G.E. AK-2A-25 type Reactor Trip Circuit Breakers.

One bulletin action request was the performance of a surveillance test of the UV trip function independent of the shunt trip function. On March 15, 1983, the licensee measured excessive undervoltage trip response times on four of sixteen breakers. Two breakers on Unit 1 tripped in the range of 5 to 6 seconds. Two breakers on Unit 2 tripped in the range of 1 to 2 seconds. Independent shunt trip tests were all instantaneous. Because the licensee was measuring response times by stopwatch, obtained data was only approximate. Unit 1 and 2 Technical Specifications require "Reactor Trip System Response Times" (the time interval from when the monitored parameter exceeds its trip setpoint at the channel sensor until electrical power is interrupted to the control element assembly drive mechanism) on the order of 400 msec. The different trip functions have varying trip response times.

On March 15, 1983, the licensee reported the longer trip times noted above for the two Unit 1 breakers and the two Unit 2 breakers to the inspector. The inspector recommended that the licensee make an Emergency Notification System (ENS) Report. On March 15, 1983, the licensee reported by ENS the delayed breaker trips on Unit 1, which were the two longest trip times. On March 16, 1983, the licensee performed additional UV trip testing using a visicorder for time measurements. Each breaker was tripped three times. The following breaker trip times were recorded.

Unit #	Trip Circuit Breaker (TCB)#	Trip Times (Seconds)
1	1	1.28,4.04,8.6
1	2	0.36,0.168,0.31
1	3	0.112,2.30,0.06
1	4	8.47,5.32,0.36
1	5	0.48,0.34,0.32
1	6	0.13,0.06,0.07
1	7	0.06,0.05,0.06
1	8	0.06,0.06,0.06
2	1	0.14,0.07,0.06
2	2	0.06,0.07,0.06
2	3	24.64,0.06,0.07
2	4	0.07,0.07,0.09
2	5	0.10,0.06,0.07
2	6	0.1,0.09,0.11
2	7	0.20,0.16,0.68
2	8	0.71,0.60,1.23

On March 16 and 17, 1983, the licensee performed corrective maintenance on TCB's Nos. 1,3, and 4 on Unit 1 and Nos. 3,7, and 8 on Unit 2 using procedures based upon the G.E. Technical Manual and G.E. Service Advice Letter #175. The work was done under Unit 1 MR-E-83-102 and Unit 2 MR-E-83-103 and principally consisted of correcting the "Positive Trip Adjustment" on the breaker trip shafts. The six TCB's which were adjusted were then retested at least five times in the shop (visicorder timed) and once in the field after reinstallation (confirmation test without timing device). On March 17, 1983, the licensee reported by the Emergency Notification System that all testing on the Unit 1 and Unit 2 TCB's had been completed and that all breakers tripped on UV in less than 0.5 seconds and instantaneously by shunt trip. The inspector observed the major portion of the March 15 and 16 in place TCB timing tests and the correction of the "Positive Trip Adjustment" for one TCB on March 17, 1983. The licensee submitted a written response to this bulletin on March 21, 1983. The response included:

(1) A summary of the undervoltage trip testing results and provided a listing of trip times for breakers which required corrective maintenance (before and after adjustment);

(2) A statement that all Electrical and Controls testing and maintenance procedures associated with corrective and preventive maintenance activities performed on RPS trip devices have been verified for conformance to manufacturers recommendations;

(3) The maintenance performed on the breakers with delayed trip times;

(4) A description of a procedure change that had been made and the guidance that had been given to operators regarding manual tripping of the reactor should an automatic trip fail to occur;

(5) A summary of Reactor Trip breaker malfunctions that have occurred in the past at the Calvert Cliffs plant; and

(6) A summary of the Quality Controls that have been maintained relative to the purchase of the Reactor trip breakers.

On March 25, 1983, the inspector noted that change CCOM 83-56, dated March 16, 1983, had been incorporated into EOP 1, "Reactor Trip", Revision 11, dated April 7, 1982. This change added a note instructing the operators to manually trip the Reactor in the event of automatic trip failure. This bulletin will remain open pending NRC determination of whether additional licensee action(s) will be required relative to the subject of undervoltage trip failures for reactor trip breakers.

--IE Bulletin 83-01, Failure of Reactor Trip Breakers (Westinghouse DB-50) to Open on Automatic Trip Signal. This bulletin was sent to the licensee on February 25, 1983. For Pressurized Water Reactors not using the subject breakers a negative declaration was required within seven days. As noted above in the licensee's response to IEB 83-04, the subject breakers are not used. A declaration to this effect was sent by the licensee in a letter to the Director, Office of Inspection and Enforcement, dated March 3, 1983. This bulletin is closed.

12. Dose Calculation System Comparisons

During this report period the inspector ran comparisons between the licensee's computer based dose calculation system and the NRC's IRDAM (Integrated Rapid Dose Assessment Model). The licensee uses the Meteorological Indiction and Data Indication System (MIDAS), a remote computer-based system leased from Design Graphics in Rockville, Maryland. MIDAS uses current meteorological and radiation monitoring system data which is updated at 15 minute intervals. Some of the data which is available through MIDAS include outside air temperature, differential temperature (200 to 40 feet elevations), wind speed, wind direction, rainfall, and Unit 1 and Unit 2 Noble Gas Monitor readings. This data was available for a continuous period of time (at least 30 days) prior to the test comparisons. Results of the comparisons are summarized in the table below. Some correlation between the data was noted, however, the differences were substantial, perhaps due to differences in modeling. The MIDAS system uses finite cloud correction factors, accounts for decay of radioactivity after the plume has left the stack, and has and considers terrain mapping capabilities. The IRDAM system uses straight line semi-infinite cloud dispersion factors. The inspector noted several potential problem areas in the MIDAS program. One example was conversion of wind speed to meters per second (18.5 miles per hour converted to 8.27 meters per second by both IRDAM and hand calculations; 7.8 meters per second by MIDAS). As a second example, in the second problem, peak offsite whole body dose rate, which is highlighted by MIDAS, was less than the calculated whole body dose rate at the site boundary (1.9 E-4 mrem per hour peak offsite dose rate vs 2.5 E-4 mrem per hour whole body dose rate at the site boundary). As a third example, in the second problem the MIDAS calculated maximum integrated whole body dose (R) was a factor of 20 greater than the dose calculated by multiplying the maximum MIDAS generated offsite whole body dose rate (R/hr) by the appropriate time duration. These discrepancies were pointed out to the licensee. The results of the inter-comparisons are unresolved will be further evaluated by the NRC (317/83-07-06).

Function	Distance to Calculated Value (Miles: IRDAM/MIDAS)			
	Site Boundary*	1.9/2.0	5/5	12.4/10
CASE 1				
I. Whole Body Dose Rate (R/hr)				
A	3.88E-1	1.92E-1	5.18E-2	1.65E-2
B	6.9E-2	3.41E-2	9.2E-3	2.93E-3
C	4.2E-2	2.3E-2	7.2E-3	2.9E-3
D	3.7E-2	2.6E-2	8.2E-3	2.8E-3
E	0.88	1.13	1.14	0.96
II. Thyroid Dose Rate (R/hr)				
A	2.57E1	1.72E1	3.42	1.09
B	4.67E1	2.3E1	6.22	1.98
C	8	7.8	2.8	1.2
F	5.8	2.9	2.2	1.65
III. CHI/Q Value				
A/B	1.7E-5	8.43E-6	2.28E-6	7.25E-7
C	6.1E-6	6E-6	2.2E-6	9.4E-7

CASE 2

I. Whole Body Dose Rate (R/hr)				
A	7.67E-7	9.69E-8	4.07E-8	1.83E-8
B	3.64E-7	4.6E-8	1.93E-8	8.72E-9
C	2.5E-7	7.3E-8	3.3E-8	1.9E-8
D	2.8E-7	4.2E-8	1.93E-8	8.72E-9
E	1.12	0.58	0.58	0.46
II. Thyroid Dose Rate (R/hr)				
A	4.9E-4	6.2E-6	2.61E-6	1.18E-6
B	2.47E-4	3.12E-5	1.31E-5	5.9E-6
C	9.9E-5	3.1E-5	1.4E-5	8E-6
F	2.49	1	0.93	0.73
III. Integrated Whole Body Dose (R)				
A	6.13E-6	7.75E-7	3.25E-7	1.47E-7
B	2.92E-6	3.68E-7	1.55E-7	6.97E-8
C	4E-5	4.5E-6	5E-7	8E-8
D	2.25E-6	3.42E-7	1.55E-7	6.97E-8
E	0.056	0.076	0.31	0.87
IV. Integrated Thyroid (R)				
A	3.94E-4	4.98E-5	2.09E-5	9.42E-6
B	1.97E-3	2.49E-4	1.05E-4	4.72E-5
C	6E-4	2E-4	1E-4	6E-5
F				
V. CHI/Q Value				
A/B	2.87E-7	3.62E-8	1.52E-8	6.84E-9
C	2.4E-7	7.4E-8	3.4E-8	1.9E-8

A = IRDAM Gross Release Rate Method
B = IRDAM Isotopic Release Rate Method
C = MIDAS
D = IRDAM Isotopic Adjusted for Finite Cloud
E = Ratio IRDAM Isotopic corrected to MIDAS Dose (Rates)
F = Ratio IRDAM Isotopic Iodine to MIDAS Dose (Rates)

* CASE 1 Average IRDAM Values for 0.6 and 1.2 miles, MIDAS 0.9 miles.
CASE 2 0.6/0.8.

CASE 1 Elevated Release, wind from 000 at 5 mph, 61.7 ci/sec, Stability Class D, 2.7% Iodine, Release at t=0, 8 hr duration.
CASE 2 Elevated Release, Current Meteorological Data (wind from 313, WS 18.5 mph, temperature difference 5.4 degrees F, 7.24E-3ci/sec. Release Rate), Release at t=0, 8 hr duration (=Stability Class A).

13. 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:

--February, 1983 Operations Status Reports for Calvert Cliffs No. 1 Unit and Calvert Cliffs No. 2 Unit, dated March 16, 1983.

--Revisions for the Operations Status Report for Calvert Cliffs No. 1 Unit, dated March 17, 1983.

--Special Report of February 6, 1983 Fire Protection System event, dated March 21, 1983.

No unacceptable conditions were identified.

14. Unresolved Items

Unresolved items require more information to determine their acceptability and are discussed in Details 3.b, 3.e, 4, 10, and 12.

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.