U. S. NUCLEAR REGULATORY COMMISSION

Region I

DCS Nos.				
	50317822510	50317820911	50317821127	50320792903
	822610	822911	822312	50318830701
	822710	821011	822812	831201
	830401	830501	830701	830401
	50318822211	50318822411	50318822812	830101

Docket Nos. 50-317
50-318

Report Nos. 82-30
82-27

License Nos. DPR-53
DPR-69

Licensee: Baltimore Gas and Electric Company

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

Inspection At: Lusby, Maryland

Dates: December 16, 1982 - January 11, 1983

Submitted: for D. R. Johnson
R. E. Architzel, Sr. Resident Inspector — 2/3/83 date

for D. R. Johnson
D. C. Trimble, Resident Inspector — 2/3/83 date

Approved: for D. R. Johnson
E. C. McCabe, Jr., Chief, Reactor Projects Section 2B — 2/3/83 date

Summary: December 16, 1982 - January 11, 1983 (Inspection Report 50-317/82-30; 50-318/82-27)

Areas Inspected: Routine resident inspection (128 hours) of the control room, accessible parts of plant structures, plant operations, radiation protection, physical security, fire protection, plant operating records, maintenance, surveillance, radioactive waste releases, open times, TMI Action Plan items, and reports to the NRC. One violation was found: failure to document, in a Non-Conformance Report, a non-compliance with administrative procedures (Detail 13).

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DETAILS

1. Persons Contacted

The following technical and supervisory personnel were contacted:

D. E. Buffington, Fire Protection Inspector
J. T. Carroll, General Supervisor, Operations
J. A. Crunkleton, Supervisor, Electrical Maintenance
C. L. Dunkerly, Shift Supervisor
W. S. Gibson, General Supervisor, Electrical and Controls
D. W. Latham, Principal Engineer, Operational Safety and Licensing
J. F. Lohr, Shift Supervisor
C. R. Mahon, Outage Coordinator
J. E. Rivera, Shift Supervisor
L. B. Russell, Plant Superintendent
R. Shea, Investigator, Security
J. Sites, Supervisor, Instrument Maintenance Unit 1
J. A. Snyder, Supervisor, Instrument Maintenance Unit 2
K. L. Strupp, Supervisor, Quality Control - Modifications
J. A. Tiernan, Manager, Nuclear Power Department
D. Zyriek, Shift Supervisor

Other licensee employees were also contacted.

2. Licensee Action on Previous Inspection Findings

(Closed) Violation (318/82-19-01). Failure to Implement the Site Emergency Plan for a Radiological Event. The licensee responded to this item in a letter dated October 26, 1982. The inspector verified that the General Supervisor, Operations, had discussed this event with the Shift Supervisor involved, and all licensed operators were made aware of the details of this incident by routing a copy of the Notice of Violation and the BG&E reply (Operations Routing Slip No. 348 dated 10/22/82).

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. These checks were performed on the following dates: December 16, 21, 22, 27, 28, 29, 1982; January 4, 5, and 7, 1983.

On 12/16/82, immediately prior to the commencement of the Unit 2 Containment Integrated Leak Rate Test (ILRT), the inspector noted that Unit 2 Operations personnel had selected the #23 High Pressure Safety Injection (HPSI) Pump discharge to the #22A Reactor Coolant Loop as the emergency boration path. The inspection further noted that the HPSI flow indicator for that path was inoperable and pointed that fact out to the operators. All other HPSI flow paths were tagged shut for the ILRT. The Shift Supervisor then directed that the emergency boration path be shifted to a HPSI loop with an operable flow indicator prior to beginning the ILRT.

On 12/27/82, the inspector noted that the scale was missing on the Control Room Wind Speed Indicator/Recorder and reported this to the Senior Control Room Operator (SCRO). The SCRO looked into the problem and found that a maintenance activity had just been completed (within the last half hour) on the instrument by a technician out of the Baltimore office. The technician had removed the scale without informing operations personnel and was taking it offsite to use as a reference in making an improved scale for the instrument. The SCRO annotated the windspeed recorder chart paper so that windspeed could be determined by use of divisions printed on the recorder paper. He then initiated action to have the instrument scale replaced. The inspector discussed the incident with the Shift Supervisor and Acting General Supervisor of Operations (GSO). He expressed concern with plant administrative controls and about the possibility that this may indicate a more general deficiency in the training of offsite support personnel. The Acting GSO stated that he would discuss the inspector's concerns with the GSO to determine if additional, corrective action was necessary. This item will be reviewed during a future inspection (317/82-30-01).

b. Weekly System Alignment Inspection

Operating confirmation was made of selected piping system trains. Accessible valve positions in the flow path 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:

-- ECCS Pump Room Exhaust Train #11 on 1/7/83.

-- Unit 1 Auxiliary Feedwater System on 12/23/82.

-- Various valves inside Unit 2 Containment on 12/22/82 and 1/3/83.

No unacceptable conditions were found.

c. Biweekly Inspection

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

-- 34309, Unit 1 Safety Injection MOVs, initiated 9/23/82, checked on 1/7/83.

-- 377, Removal of 2 RV-200, initiated on 11/18/82, observed on 1/3/83.

-- 118, Unit 2 Reactor Coolant Pump Controlled Bleedoff Flow Element Isolation on 1/3/83.

During a tour of the Unit 2 Containment on 1/3/83, the inspector reviewed the implementation of Tagout 377, which required the removal of one of the two pressurizer safety valves to ensure that a vent path of greater than 1.3 square inches existed. Technical Specifications LCO 3.4.9.3 requires that either two power operated valves, with a lift setting of less than 450 psig, or a Reactor Coolant System (RCS) vent of greater than 1.3 square inches be operable whenever the RCS cold leg temperature is less than 275 degrees F. The inspector noted that although the safety valve had been removed, it had been oriented 90 degrees to the initial position and bolted in a canted fashion with the throat of the valve and the pipe to the RCS in close proximity. This raised a question whether an actual opening of greater than 1.3 square inches existed. At the time the situation was observed, both power operated relief valves were tagged out of service; and the Reactor Coolant System temperature was 163 degrees F. Both the reactor vessel head vent (0.785 square inches) and the pressurizer vent (0.442 square inches) were open at the time in addition to the opening that existed in the pressurizer safety valve. A chain, which indicates a locked, open valve, was installed between this safety valve and its flange. The licensee separated the valve from its flange to ensure an adequate opening. Measurements of the opening that existed had been made immediately prior to this. The inspector reviewed the licensee's calculations which indicated an opening of 0.789 square inches existed through the safety valve. Therefore, the total area of the opening which existed was over two square inches, satisfying the Limiting Condition for Operation. The Plant Operations and Safety Review Committee reviewed the circumstances surrounding the improper tagging in meeting 83-03 on 1/7/83, but delayed completion of their review pending further investigation. Completion of the licensee's review and any additional correction is unresolved and will be reviewed by the NRC (318/82-27-01).

Boric acid tank samples were compared to the Technical Specifications. Tank levels were also confirmed. No unacceptable conditions were found.

d. Other Checks

During plant tours, the inspector observed shift turnovers and use of radiation work permits, protective clothing, and respirators.

Personnel monitoring practices and area radiation and air monitor use and operational status were reviewed. Equipment tagouts were sampled for conformance with LCO's. Plant housekeeping and cleanliness were evaluated. Other LCO's, including RCS Chemistry and Activity, Secondary Chemistry and Activity, watertight doors, and remote instrumentation, were checked.

During a review of the onsite 120 V AC Vital Instrument power system, the inspector noted that all four inverters on Unit 1 share a common backup power supply (inverter backup bus #11). The same condition exists on Unit 2 with its backup power supplied by inverter backup bus #21. The inspector then reviewed Technical Specifications (TS's) and licensee's administrative controls to see if sufficient measures were in place to prevent, in the worst case, placing all unit inverters on the backup power bus simultaneously and thereby losing redundancy in power supplies. Licensee administrative controls were established in the form of procedural precautions in OI 26B, Revision 6, dated 12/82 and through providing only one key (a key is needed to shift inverter power supplies) per unit to Operations personnel. Since the key is "captured" in an inverter lock when a power shift is made, the key could be used only to transfer one inverter. TS's do not specifically address the inverters. A previous edition of TS's had specifically allowed only one inverter to be placed on the backup bus at any one time. The inspector asked the General Supervisor of Operations (GSO) to assess whether a TS change should be initiated to again include a restriction on inverter shifts. The GSO agreed to do this. The GSO later stated that T.S. 3.4.8.6 requires tie breakers between redundant buses to be open and that this means that redundant inverter buses cannot be tied together through simultaneous selection to a backup bus. The inspector had no further questions.

Prior to an entry into the Unit 2 Containment on 1/3/83, the inspector reviewed the Containment Access vital area log sheet. One worker was noted to have signed in on RWP 102 for work on the 45 foot level of the Containment. The inspector noted that this number was not valid for work inside the Containment, as all Containment RWPs were numbered starting above 2003. The inspector discussed this with the Radiological Control Shift Supervisor who investigated the work ongoing and determined that the individual was erecting scaffolding inside the Containment under the wrong RWP number. The RWP he was working under was for erecting scaffolding in the Auxiliary Building. The Radiological Control Shift Supervisor stated that a report had been sent to the individual's supervisor describing the situation and requesting corrective action to ensure that the individual signed in on the proper RWP in the future. The inspector had no further questions.

On 1/3/83, the inspector noted seven sheets of plywood stacked on the 69 foot elevation of the Unit 2 Containment. The inspector could not find any marking on the most accessible plywood sheet that would indicate that it had been treated with a fire retardant. The inspector notified the licensee's Fire Protection Inspector of his finding. The Fire Protection Inspector stated that the licensee has established a control program which should prevent the use of untreated wood and described the markings placed on treated wood. The Fire Protection Inspector stated that he would have the plywood examined and, if necessary, removed. The plywood in question had already been removed when the Fire Protection Inspector went to examine the wood. The inspector had no further questions.

On 12/23/82, the inspector noted that an indicator on the Unit 1 Remote Shutdown Panel was inoperable (Letdown Line Temperature, TI-223). The inspector noted this to the Senior Control Room Operator who stated that he would initiate maintenance action to correct the problem. Additionally, the inspector checked Technical Specifications to verify instrument operability requirements were satisfied. No unacceptable conditions were found.

4. <u>Review of Events Requiring One Hour Notification to the NRC</u>

The circumstances surrounding the following events requiring prompt (one hour) NRC notification per 10 CFR 50.72 via the dedicated telephone (ENS-line) were reviewed.

a. At 4:20 p.m. on 12/28/82, #22 vital inverter tripped, resulting in a loss of Shutdown Cooling and an undervoltage (UV) trip of #24 4KV vital bus. The inverter trip interrupted power to a Reactor Coolant System pressure sensor which caused the Shutdown Cooling (SDC) suction valves to close. The operator noted the valve closures and stopped #21 Low Pressure Safety Injection (LPSI) Pump which was supplying SDC. The inverter trip also interrupted power to the B Engineered Safety Features Actuation System (ESFAS) logic cabinet causing a spurious undervoltage trip of the #24 4KV bus. Shutdown Cooling was restarted at 4:32 p.m. The actuation of the ESFAS undervoltage to #24 4KV bus is apparently not unusual. A similar actuation occurred on 11/9/82 when the DC input feeder to #11 inverter was inadvertantly opened by contract personnel pulling cable in the Unit 1 Cable Spreading Room. During this event, a voltage transient on the AC load side of the #11 vital inverter resulted in blowing input fuses from the DC power supply. Although the logic cabinets require power to send an actuation signal and no signal is sent when the logic cabinets are merely deenergized by opening their power supply breaker, removing power from the cabinets by deenergizing DC power to the inverters results in voltage transients which initiate the UV actuation prior to complete deenergization of the actuation cabinet. The cause of the voltage spike on the AC side of #22 vital AC inverter was not identified.

b. With Unit 2 in Mode 5 operation at 10:12 p.m. on 12/30/82, Safety Injection Actuation System (SIAS) activation occurred. No water was injected into the Reactor Coolant System. The actuations were caused by personnel error. ESFAS sensor cabinet ZG was deenergized by Operations personnel at the request of I&C technicians, while sensor cabinet ZF was in a tripped condition undergoing a surveillance test.

c. With Unit 2 in Mode 5 at 2:30 a.m. on 1/1/83, all 'A' ESFAS train logic channels actuated. The #21 4KV bus was deenergized, #12 Diesel Generator started as designed, and the #21 4KV bus was reenergized. The exact cause of the actuations was unknown but was related to a voltage drop on #21 120 V AC vital bus (the bus supplying power to the 'A' ESFAS logic cabinet).

d. At 3:05 a.m. on 1/4/83, the #21 4KV vital bus was lost following a trip of #21 vital inverter. The unit was in cold shutdown when the transient was initiated during a Reactor Protection System (RPS) surveillance test. Diesel Generator #12 started as designed. It had to be manually closed on the bus (no SIAS signal present) and loads restored manually (no power to the Shutdown Sequencer). All loads were returned to normal by 3:20 a.m.

   Shutdown cooling was lost because of the loss of vital power to the pressure sensing instrument (2-PIC-103) controlling the motor-operated valves in the suction line from the Reactor Coolant System, resulting in closure of the valves and loss of a suction path. The #21 vital AC bus was shifted to the backup power supply and Shutdown Cooling restored within 15 minutes.

   The inspector reviewed the Sequence of Events computer alarm printouts and the licensee's investigative and corrective actions. During the RPS surveillance, a power supply lead for the drawer for Wide Range Nuclear Instrument 'A' had been caught on the drawer underneath, while the drawer was being drawn out. This caused the lead to be chafed, resulting in a ground which opened the input circuit breaker for the 'A' RPS cabinet. Computer alarms indicated that (sequentially) a ground condition had existed on the #21 vital bus, followed by a return to normal for the bus, followed by an entire set of ESFAS Channel 'A' actuations, followed by a low voltage alarm on the #21 vital bus. Prior to being cleared by the circuit breaker action, the short circuit had apparently induced a voltage transient (drop and return to normal) of sufficient magnitude to actuate the 'A' ESFAS logics powered by the same inverter. The induced transient had also apparently been of sufficient magnitude to blow the DC input fuses to the vital inverter, resulting in a loss of the vital bus. This resulted in no power available to actuate the 'A' train ESFAS equipment, although a momentary signal had apparently been generated. As described above for the event on 12/28, although ESFAS actuations need power to actuate and no actuations occur if an actuation cabinet is turned off by securing AC input, undervoltage actuation occurs and deenergizes the associated 4KV vital bus if the loss of power is initiated by a loss of DC power to the inverters. The licensee felt the reason might be interactions within the inverters as they loose power.

The licensee thought that a current limiting feature of the inverters may have caused the voltage transient. The inspector also questioned the licensee concerning why the DC input fuses had blown to the inverter, considering the fact that the RPS cabinet circuit breaker had opened and vital AC voltage had apparently been restored to normal following the ground.

The licensee discussed proposed testing (by intentional initiation of shorts on the vital AC bus for Unit 2) with the inspector and approved a plan for testing on the afternoon of 1/4/83. Following a very similar set of initiating events on Unit 1 on 1/5/83, resulting in ESFAS actuation from 100% power (see paragraph 4.e), the test program was accelerated and performed during the evening of 1/5/83, prior to Unit 1 restart. The testing was performed under MR-E-83-004 and observed by the inspector.

The licensee duplicated the initiating event by installing two 20 amp fast blow fuses (SHAWNUT Form 101 type fuses recommended by the vendor) in series between the phases of the AC output. A Visi-Corder instrument was used to monitor the inverter current and voltage response. The Unit 2 ESFAS features had been disabled as allowed in Mode 5 and the 4KV bus to be affected had been aligned to an operating diesel generator prior to the test. During the test, the inverter output current limiting circuitry responded to the current surge before the fuses cleared the fault, reducing the 120 inverter output to about 20 volts for about 0.75 seconds. The voltage then ramped back up to normal voltage. This action effectively removed power from the associated actuation cabinet, then subsequently restored power, and initiated the actuations. Repeat testing with 12 amp fast blow fuses resulted in clearing the fault without actuating the current limiting circuitry; consequently, no actuations of ESFAS occurred. The licensee concluded that the manufacturer's recommendation to fuse all branch circuits with fast acting fuses rated at less than 25% of inverter output appeared necessary. This would result in a maximum fuse size of 15 amps. The licensee initiated a Facility Change Request to examine fuse requirements within branch circuitry. Completion of the engineering review and facility change will be followed by the NRC (318/82-27-02).

Various aspects surrounding the sequence of events remain of concern. The inspector noted, and the licensee confirmed, that blowing of the DC input fuses to the vital AC inverters was occurring frequently (not always) on minor grounds on the AC load sides of the inverters resulted in actuation of the current limiting feature. The inspector further noted that the current limiting feature of the vital AC inverters that stepped down inverter voltage immediately and restored the voltage in about one second was of questionable value when the end result is actuation of the Engineering Safety Features. From full power, the normal sequence of events would be as described in paragraph 4.e, including the Containment Spray actuation. In the event the DC input fuses blow, the 4KV vital bus would be deenergized, and the associated diesel generator would start, but no power would be available to the appropriate shutdown sequencer to restore loads automatically. The inspector requested that the licensee review the design adequacy of the features. This item is unresolved (318/82-27-03).

e. At 8:33 a.m. on 1/5/83, Unit 1 tripped from 100% power following a spurious actuation of all 'A' train ESFAS channels, including Steam Generator Isolation, Containment Spray, Safety Injection, Recirculation Actuation and Containment Isolation. Pressure remained above the shutoff head of the HPSI pumps. Refueling Water Tank level decreased by about 1300 gallons and was sprayed into Containment. ESFAS channels were quickly reset. Plant systems and conditions were restored to normal for Mode 3. During the event, as a result of the ESFAS actuation, the normal power feeder breaker tripped for the #11 4KV bus. Diesel Generator #11 started as designed and reenergized the bus. The reactor tripped on low Steam Generator water level caused by shrinkage following the closure of the Main Steam Isolation Valves.

The inspector was in the Control Room at the time of the trip and observed the licensee's actions and the plant response. The cause of the actuations was a technician inadvertently shorting the power supply terminals on the Control room indicator for the Unit 1 Containment High Range Radiation Monitor (1-RI-5317). The technician stated that this instrument was protected by 30 amp supply fuses. The fuses in question did not blow, nor was the short of sufficient magnitude to leave a mark on either the instrument terminals or the mini-clamps being used by the technician for taking measurements. The sequence of events was similar to that described in paragraph 4.d above and confirmed by subsequent testing on Unit 2.

The licensee conducted Containment inspections to evaluate the consequences of the Containment Spray actuation. The inspectors accompanied licensee personnel during these inspections. No damage to equipment from the Containment Spray was observed. One electrical ground appeared on the Containment Overhead Crane (non-safety-related); however, this cleared by itself within 15 minutes. Unit 1 was restarted and returned to power operations at 3:00 a.m. on 1/6/83. Pressurizer level deviations (expected) were reported to the NRC during the restart.

f. At 6:56 p.m. on 1/7/83, while Surveillance Test Procedure STP-O-7-2 was in progress (testing ESFAS Recirculation Actuation (RAS) Channel B), the #22 Low Pressure Safety Injection (LPSI) pump stopped, as designed. The #22 LPSI pump was providing Shutdown Cooling (SDC) at the time. The operator did not immediately realize that SDC flow had stopped. At 7:05 p.m., the operator recognized the problem and restarted #22 LPSI pump.

The inspector reviewed STP-O-7-2, through Revision 25 approved 2/10/82. The STP had no warning or precautionary steps to alert or remind the operator performing the test that SDC flow would be lost if the LPSI pump for the train being tested was supplying SDC. The operator must read several steps ahead in the procedure before carrying out the RAS test to be reminded that the LPSI pump till trip. The inspector pointed out this procedural inadequacy to the Operations Engineer in charge of the Operations Surveillance Program. That engineer stated that he would initiate a change to the STP which would include an appropriate warning to operators. The General Supervisor, Operations (GS,O), also stated that the reactor operator in question was newly licensed (license received 12/24/82), and that inexperience may have been a contributing factor in that the operator should have recognized that actuating RAS would result in tripping the LPSI pump. The GS,O further noted as a contributing factor that this STP is performed both at power and while shutdown and that an actuation at power would not require such a precaution because the LPSI pump would not be running. Licensee action on this item will be reinspected (318/82-27-05).

g. An unplanned Safety Injection Actuation (SIAS) occurred on Unit 2 at 6:20 p.m. on 1/12/83. The unit was in Mode 3, heating up to normal operating pressure and temperature. The cause was operator lack of awareness of the new SIAS initiation setpoint during maintenance on pressurizer spray valve 100F which was being cycled for adjustment. Pressure dropped from 1840 to 1720 psia, through the actuation setpoint. Equipment operated as designed and systems were quickly restored. The Senior Control Room Operator thought that sufficient pressure margin existed at the time of the opening of the spray valve (the setpoint had been raised from 1578 to 1725 psia during the recently completed refueling outage as required by the Cycle 5 reload application). Revised Technical Specifications had not been received by the licensee; however, operators had been trained on the new setpoints, and these had been implemented for Unit 1. The inspector reviewed the transient with Control Room personnel and technicians. Computer printouts and recorder charts were also examined. The spray valve needed adjustment for full open indication and stroke times. The only significant effect on the plant was to isolate letdown, start all three charging pumps, and shift their suction to the Boric Acid Storage Tanks (pressure remained above the shutoff head of the HPSI pumps). Additional aspects of this actuation remained to be examined and followed by the NRC at the close of the inspection period (318/82-27-04).

h. On 12/23/83, both Diesel Generators supplying power to Unit 1 were inoperable for about a 40 minute period beginning at 6:15 p.m. Diesel Generator #11 had been placed out of service for maintenance at 3:15 p.m. Number 12 Diesel Generator had been tested for operability prior to removal from service of #11 Diesel Generator. At 3:44 p.m., #12 Diesel Generator had been aligned to the #11 4KV bus (an off-normal lineup) to perform a one hour full load run. This was done to burn off lubricating oil which carries over into the diesel exhaust and to ensure that a backup source of power was available for the only operable control room air conditioning unit. When the Diesel Generator was shutdown about 5:00 p.m., the Shutdown Sequencer Alarm, normally on when a diesel is running, failed to reset. Operators cleared the alarm by shaking the front of the breaker panel. To check whether or not the problem had been corrected, the licensee restarted the Diesel Generator at 6:15 p.m., at which time it was discovered that the Shutdown Sequencer would not work. Number 12 Diesel Generator was realigned to the normal (14) 4KV bus. Operability of one diesel generator was restored at 6:55 p.m. At 8:15 p.m., a controlled power decrease was initiated on Unit 1 as required by Technical Specification 3.05, due to the lack of backup power for the Control Room Air Conditioning Unit. At 9:30 p.m., the power decrease was terminated when maintenance actions had been completed on #11 Diesel Generator and it was returned to service.

Investigation by electricians revealed that a linkage had come loose in the breaker supplying power from #12 Diesel Generator to #11 4KV bus. The linkage was repaired and a successful transfer of Diesel Generators to alternate buses conducted and tested at 12:30 a.m. on 12/24/82. Inspector review of this event revealed that a similar problem occurred earlier in the day during an attempted transfer of #12 Diesel Generator to #11 4KV bus. Diesel Generator auxiliaries did not function because of dirty contacts in the disconnect to the backup bus. This problem had been identified during the initial transfer attempt of #12 diesel to the backup bus; therefore, the licensee terminated the transfer attempt and restored the diesels to normal lineup. Because the diesels had not been successfully transferred, the licensee did not enter an action statement for the earlier transfer. (The process of transferring diesel generators between busses results in a loss of automatic starting of the diesels for about 40 minutes). The inspector questioned the General Supervisor, Operations, concerning the reportability of the second event. The inspector noted that the licensee had actually declared the #12 Diesel Generator operable and, subsequently, inoperable on the backup bus and had entered into a degraded mode upon discovery of the inoperability of the diesel. Therefore, a degraded condition existed, and the event should be reported. The licensee acknowledged the comments after reviewing the sequence of events and stated that a Licensee Event Report would be submitted. The licensee further stated that the apparent causal factor was the infrequent alignment of the #12 Diesel Generator to the alternate DC buses and the infrequent operation of this equipment. The licensee stated that they would consider a preventive maintenance program to test this equipment. Submission of the required report and the licensee's actions to minimize the chances of recurrence will be followed by the NRC (317/82-30-02).

5. Radiation Waste Releases

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

- -- Liquid Permit M-203-82 12/23/82, release of Miscellaneous Waste Monitoring Tank, reviewed on 1/5/83.
- -- Gaseous Waste Permit G-138-83 Ventilation (beginning 11/9/82) of Unit 2 Containment during the Refueling Outage, reviewed on 1/5/83.
- -- Gaseous Multiple Release Permit GMRP 35, Units 1 and 2 Vent Release, reviewed on 1/5/83.

No unacceptable conditions were identified.

6. 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, isolation zones, vehicle searches, personnel identification, access control, badging, and required compensatory measures.

About 10:30 a.m. on 12/17/82, the licensee notified the NRC of an incident of malicious tampering within the Turbine Building, in accordance with the requirements of 10 CFR 50.72. The inspector reviewed and observed the licensee's corrective and investigative actions. Vital areas and equipment were not involved. No unacceptable conditions were identified.

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

LER's submitted to the NRC 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			
82-65	10/25/82	11/24/82	Containment atmosphere particulate and gaseous radioactivity monitoring system inoperable.
82-66	10/26/82	11/24/82	RPS Channel trip units for hi-power thermal margin/flow pressure and axial shape index bypassed.
82-67	11/09/82	12/09/82	Safety Injection Tank Level Transmitter inoperable.
82-68	11/09/82	12/08/82	DC feeder breaker to 120 Volt AC vital bus #11 inverter inadvertently tripped open causing reactor trip.
82-69	11/29/82	12/23/82	Auxiliary Feedwater Pump inoperable.
82-71	11/09/82	12/16/82	#12 Charging Pump inoperable.
82-72	10/27/82	11/19/82	Oyster samples collected per ETS showed Ag-110m to be 363+/8-8pCi/kg (wet).
82-73	11/10/82	12/09/82	Pressurizer level deviated from program level by more than 5%.
82-74	11/27/82	12/23/82	Water leaked from cracked weld on #11 Charging Pump Discharge Drain Line.
82-79	12/09/82	01/06/83	Pressurizer level deviated from program level by more than 5% two times.
Unit 2			
82-53	11/22/82	12/20/82	Shutdown cooling flow lost.
82-54	11/24/82	12/23/82	Power lost to #24 4KV bus resulting in loss of a saltwater pump and #22 LPSI pump, disabling shutdown cooling.

No unacceptable conditions were found.

8. Plant Maintenance

The inspector observed and reviewed maintenance and problem investigation activities to verify compliance with regulations, administrative and maintenance procedures, and 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 were checked. The following activities were included.

-- MR E-83-004, Perform Short Circuit Test on Unit 2 ESFAS A Logic Cabinet, observed on 1/15/83.

-- MR-0-82-7097, observed stroke time adjustment for Unit 2 Chemical and Volume Control System Valves 2-CV-518 and 2-CV-519 (Loop Charging Line Isolation Valves).

No unacceptable conditions were found.

9. Surveillance Testing

The inspector observed parts of tests to assess performance in accordance with approved procedures and LCO's test results (if completed), removal and restoration of equipment, and deficiency review and resolution. The following tests were reviewed:

-- STP M-20-0, Diesel Generator Inspection (12 Diesel Generator) observed on 12/16/82.

-- Walkdown of Unit 1 Containment following Containment Spray on 1/5/83.

-- STP M210B-2, Unit 1 Reactor Protection System Functional Test observed on 12/27/82.

-- Unit 1 "Variable T-average Test", PSTP 4, Revision 13, dated 12/20/82 observed on 12/27/82.

No unacceptable conditions were identified.

10. Unplanned Actuations of Reactor Protection and Engineered Safety Features Actuation Systems (RPS and ESFAS)

A continuing problem exists in the relatively high frequency of inadvertent actuations of the RPS and ESFAS. Paragraph 4 of this report addresses actuations which occurred during the report period. Because large numbers of unnecessary challanges to safety systems leads to reduced safety, such events are significatn. The following table lists actuations which occurred fvrom 10/1/81 through 9/30/82 and were discussed with the licensee as a NRC concern during the management meeting which presented the Systematic Assessment of Licensee Performance for that period.

DATE	UNIT	DESCRIPTION	CAUSE
2/24/82	2	Reactor Trip on low Steam Generator level	Technician error shut a feedwater regulating valve

DATE	UNIT	DESCRIPTION	CAUSE
4/17/82	1	Manual Reactor Trip following individual rod drops	Technician tagged open wrong CEA drive mechanism
5/17/82	1	ESFAS Channel B actuation on undervoltage	Electrician error while working on inverter caused 120 VAC vital bus fluctuation
5/17/82	1	ESFAS Channel B actuation on undervoltage	Electrician error-opened breaker supplying 120 VAC vital power
6/04/82	1	ESFAS Channel A actuation on undervoltage	Technician error caused voltage fluctuation.
6/07/82	1	Channel A ESF actuation started one Diesel Generator	Unknown - technician error shorted instrument power
6/24/82	1	Actuation of Containment Isolation, Spray and Safety Injection	Separate maintenance interacted to cause actuation
8/04/82	1	Reactor Trip on Undervoltage	Operator opened a disconnect on a running Service Water Pump
8/05/82	1	Safety Injection Actuation	Separate maintenance tripped two pressurizer pressure channels
8/25/82	1	Partial ESFAS actuation started a HPSI and a LPSI pump and a Diesel Generator	Technician error - working in wrong cabinet

Inspection Report 317/82-18; 318/82-16, issued on 8/16/82, addressed the history of these actuations and [illegible] violation for the 8/05/82 event. The licensee was requested to address the corrective action generically. The corrective action (letter dated 9/15/82) consisted of revising the transmitter calibration procedure and training technicians.

Inspection Report 317/82-29; 318/82-25, issued on 1/03/83, noted and discussed the continued frequent occurrence of unplanned actuations. On 11/9/82, contractor personnel pulling cable in the Cable Spreading Room inadvertently opened the DC power input breaker to #11 vital inverter. This resulted in a spurious ESFAS Undervoltage Actuation with the loss of the #11 4KV Vital Bus. A reactor trip followed when the power supply to a Feedwater Regulating Valve failed to shift, resulting in low Steam Generator levels. While Unit 2 was in Mode 6, ESFAS (Safety Injection, Channel A) actuations occurred on 11/10 and 11/11/82. Both actuations were caused by technician error while performing a surveillance test. A loss of load Turbine Trip/Reactor Trip occurred on 12/8/82, when the Control Room Operator selected the Manual Sequential Mode for operation of the Control Element Drive System (CEDS). Due to plant conditions and the control logic for the CEDS, all regulating group rods began moving outward when an out motion command was given, creating an undervoltage that caused the trips. Unresolved item (318/82-25-02) was opened to follow safety system actuations caused by technician errors.

The inspector noted that the actuations have been caused by a variety of reasons, including operator and technician errors, inadequate procedures, hardware deficiencies, design problems, and unknown causes. The licensee stated that the frequency of actuations had also increased due to numerous facility modifications which were required by the TMI Action Plan and 10 CFR 50 Appendix R. The inspector acknowledged the licensee's comments and stated that additional licensee actions should be taken to lessen the frequency of inadvertent actuations, and that the licensee would be asked to address their actions to date and those planned for the future. Unresolved item 318/82-25-02 remains open.

11. 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 judgement. The following items were reviewed.

-- II.E.1.1.(2) Auxiliary Feedwater (AFW) Long-Term System Modifications. On 12/23/82, the inspector conducted a physical walkdown of the Unit 2 AFW system to review the status of modifications being performed on the system in accordance with FCR 79-1062, Revision 2, dated July 7, 1982. This item remains open, pending completion of preoperational testing and further NRC review.

-- II.F.1.5 Containment Water Level. This item, completed under FCR 80-1006, had been inspected (Report 317/82-12; 318/82-10) and left open, pending correction of a calibration problem involving fluid selection and venting. The inspector reviewed Transmitter Calibration Sheets for level transmitter 1-LT-4147 (6/24/82), 1-LT-4146 (12/10/82), 2-LT-4146 (12/10/82), and 2-LT-4147 (12/10/82). All four level transmitters were recalibrated following refilling and venting the internal fluid of the capillary action level transmitters. The inspector also examined the new physical installations of the transmitters in both containments and observed proper readouts of the instruments in the Control Room. Item II.F.1.5 is closed.

12. Emergency Plan Medical Drill

The licensee conducted a medical emergency drill on 12/16/82 to provide additional training because of problems identified in the medical emergency portion of the 9/28/82 annual emergency exercise. The licensee's performance on the 12/16/82 drill was observed by the inspector and a NRC Region-based specialist. The drill began at 9:55 a.m., terminated at 11:00 a.m., and was followed by a licensee conducted critique. The following areas for improvement were identified:

a. The initial paging announcements were not loud enough to understand.

b. There was some misunderstanding regarding which Emergency Work Permit (EWP 001 or 005) the response teams were using.

c. Three of the four First Aid team members responding to the drill had full beards that would interfere with their ability to use a respirator (in proper facial seal) and, therefore, their ability to respond to emergencies in areas with airborne radiological hazards.

d. The security guard accompanying the team as a communicator was unaware of the increased radiation exposure limits specified in the pre-prepared EWP's which would be used by the team (such as the limit for life saving actions).

An actual personnel injury (no contamination involved-broken arm) occurred at another location in the plant during the performance of the drill. Licensee personnel handled this actual emergency in a professional manner, and the injured individual was transported to the hospital via ambulance. Licensee performance in the drill and in handling the actual injury demonstrated satisfactory capability for coping with medical emergencies. Licensee actions on paging announcements, EQP use clarification, respirator qualifications, and EQP radiation exposure training will be reexamined (318/82-27-06).

13. Temporary Shielding

A review during the inspection period of licensee controls in the installation of temporary lead shielding (to reduce personnel radiation exposure in plant outages) revealed the following problems.

At the commencement of the Unit 1 Spring refueling outage, temporary shielding was added to Unit 1 components in eight areas including:

a. Chemical and Volume Control System (CVCS) Valves 1-CV-517, 1-CV-518, and 1-CV-519 (Loop Charging and Auxiliary Spray Stop Valves), installed about 4/20/82;

b. CVCS valves 1-CV-515 and 1-CV-516 (Letdown Isolation Valves), installed about 4/24/82.

c. All four Reactor Coolant Pumps, installed about 4/27/82.

d. Pressurizer Spray Valves 100E and 100F, installed about 4/30/82; and

e. The Reactor Coolant Drain Tank area.

A Facility Change Request (FCR 82-1030) had been initiated for Unit 1 (prior to the refueling outage) and was directed at establishing maximum numbers of temporary shielding blankets to be used in designated locations requiring shielding. That FCR arrived onsite on 4/27/83 and was approved for implementation by the Plant Operations and Safety Review Committee (POSRC) on 5/3/82 (after the shielding had been installed). The FCR was not used during the shielding installation process, nor was it processed to completion using Calvert Cliffs Instruction (CCI) 126C, dated November 24, 1981, "Administrative Control of Facility Change Request (FCR)". Quality Control personnel learned later in the outage that FCR 82-1030 had been received onsite and drafted a non-conformance report (NCR) which was directed toward the failure to install the shielding in accordance with CCI 126C and the lack of a better procedure (more appropriate than CCI 126C) for implementing temporary shielding modifications. The draft NCR was never issued and was discarded following the implementation of a procedure specifically oriented toward shielding installation (RSP 2-216, dated 10/6/82).

10 CFR 50 Appendix B, Criterion XVI, requires that measures be established to assure that conditions adverse to quality, such as non-conformances, be promptly identified and corrected. The Operations Quality Assurance Program, Revised FSAR Section 1B.16, states that controls have been established to ensure that Conditions Adverse to Quality are identified and corrective action is initiated and that non-conformances are documented in Non-Conformance Reports. Licensee Quality Assurance Procedure (QAP) 26, "Control of Conditions Adverse to Quality", establishes actions to be taken in identifying and correcting non-conformances. QAP 26, Revision 24, dated 7/28/80, effective during the first six months of 1982, specifies in Section 7.1 that non-conformances shall be documented in Non-Conformance Reports (NCRs). Section 4.4.3.2 of the same procedure classifies non-compliance with documented procedures as a type of non-conformance. The failure of QC personnel to issue an NCR as required by QAP 26 when they discovered that shielding had been installed without following the controls of CCI 126C).

During the Unit 1 shielding installation, more shielding than the maximum number of lead blankets specified in FCR 82-1030 was installed in at least one location (CVCS valves 1-CV-515 and 1-CV-516). An estimated total of 25 - 30 blankets were placed on these valves. FCR 82-1030 specified a maximum total of 15 blankets for both valves. The licensee is pursuing an engineering assessment to assure that Reactor Coolant System integrity was not degraded by the error(s) in shielding placement. Technical Specification 6.8.1 requires that procedures be established and adhered to in accordance with Regulatory Guide 1.33, Revision 2, dated February 1978. Appendix A of this Regulatory Guide specifies that general procedures are to be provided for the control of maintenance, repair, replacement, and modification work. CCI 126C establishes administrative controls for performing plant changes. The installation of the shielding was a temporary modification to the plant that was not implemented in accordance with the existing procedure for plant changes (CCI 126C). This is a violation (317/82-30-03).

During the current Unit 2 refueling outage, the licensee has maintained control of shielding through the combined use of Procedure RSP 2-216 and guidance from FCR 82-1047 (an FCR similar to FCR 80-1030 but applicable to Unit 2) in placing temporary shielding. RSP 2-216 called for Q.C. checkpoints during shielding placement. No violations were identified for Unit 2 shielding activities.

14. Review of Periodic and Special Reports

Upon receipt, periodic and special reports submitted pursuant to Technical Specifications 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 of whether any information should be classified as an abnormal occurrence, and validity of reported information. The following periodic reports were reviewed:

November 1982 Operations Status Reports for Calvert Cliffs No. 1 Unit and Calvert Cliffs No. 2 Unit, dated December 15, 1982.

BG&E letter dated November 30, 1982 documenting successful completion of the Integrated Leak Rate Test performed on June 22, 1982.

No unacceptable conditions were identified.

15. Unresolved Items

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

16. 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.