DCS Nos.	50317840112	50317831210	50318840112	50318831220
	831129	831222	831208	831223
	831130	831216	831217	831210
	831204	831213	831219	831221
	831221	831227	831125	
	840121			

U. S. NUCLEAR REGULATORY COMMISSION
Region I

Docket/Report: 50-317/84-01 License: DPR-53
50-318/84-01 DPR-69

Licensee: Baltimore Gas and Electric Company

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

Inspection At: Lusby, Maryland

Dates: January 1 - February 14, 1984

Submitted:

EC Wenzinger for 3/20/84
R. E. Architzel, Sr. Resident Inspector date

EC Wenzinger for 3/20/84
D. C. Trimble, Resident Inspector date

EC Wenzinger for 3/20/84
D. Jaffe, NRR Project Manager date

Approved: EC Wenzinger 3/20/84
E. C. Wenzinger, Chief, Reactor date
Projects Section 1A

Summary:
January 1 - February 14, 1984: Inspection Report 50-317/84-01, 50-318/84-01.
Areas Inspected: Routine resident inspection (256 hours and 29 hours by the LPM) 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, Operator Requalification Program, Saltwater System, and reports to the NRC. One Violation was found: Failure to Follow TS Requirements for the PASS and H2 Sampling Isolation Valves

DETAILS

1. Persons Contacted

The following technical and supervisory personnel were contacted:

J. T. Carroll, General Supervisor, Operations
J. R. Hill, Supervisor, Operations/Training
D. W. Latham, Principal Engineer, OL&S Unit
J. M. Moreira, General Supervisor, Electrical & Controls
P. G. Rizzo, Supervisor, Technical Training
L. B. Russell, Plant Superintendent
J. Sites, Assistant General Supervisor, Instrument and Electrical Maintenance
R. Sprecher, Supervisor, Plant Chemistry
J. M. Yoe, Instructor, Training

Other licensee employees were also contacted.

2. Licensee Action on Previous Inspection Findings

(Closed) Unresolved Item (317/80-06-04) Review Corrective Actions for Service Water (SRW) Lack of Single Failure Capability. This item concerned a total loss of the SRW system on May 20, 1980 due to air binding (air leakage into an isolated SRW Heat Exchanger from a failed tube in an Instrument Air Compressor). The licensee submitted the written report for this event (LER 80-27/01T), which was reviewed during Inspection 317/80-08. The item was left open pending completion of the licensee's corrective action and issuance of recommendations by the NRC's Office of Analysis and Evaluation of Operating Data (AEOD) following a site visit and evaluation of the event. The licensee has taken, or plans to complete, the following actions to address this event:

(1) The installation of large capacity (8 times the original capacity), alarmed, automatic vents in the SRW system which immediately vent (as needed) any air entrained in the system, mitigating the potential for air binding of the pumps. The isolation valves for these vents are locked open valves.

(2) The addition of three SRW return header check valves to the Inservice Testing (IST) program to ensure they will function as required to provide isolation of redundant return headers from one another.

(3) Removal of the SRW cross-connect between Unit 1 and Unit 2 Instrument Air compressors.

(4) Operator training will include a loss of SRW cooling due to gas ingress as a programmable malfunction in the "new" simulator.

(5) A revision to the SRW system operating procedure has been completed that prevents the accumulation of large quantities of air in the system during maintenance outages.

(6) Shortly after the event a monthly inspection of the Instrument Air compressor heat exchanger was included in Operation's Preventive Maintenance (PM) program. (After the automatic vent valves were installed, this PM was discontinued.)

AEOD issued its report (case study) of the loss of SRW on December 17, 1981. NRR forwarded a copy of the AEOD report to the licensee on September 15, 1983. The inspector reviewed an internal licensee memorandum dated October 18, 1983 addressing review of the AEOD recommendations. The Institute of Nuclear Power Operations also evaluated (evaluation dated July 29, 1983) the event and the associated AEOD report. The licensee's memorandum addressed each recommendation made by AEOD, either adopting the recommendation or justifying no action based on low probability of occurrence or minimal consequences.

(Closed) Unresolved Item (317/80-16-10) Control Room Air Conditioning Problems. This item was reinspected (Report 317/82-10) and left open pending approval of appropriate TS Surveillance Requirements. To correct the Control Room air conditioning problems the licensee installed a backup, non-safety related, air conditioning system and performed corrective maintenance on the safety grade units. As a result of these actions, system performance has improved dramatically. This was evidenced by a sharp reduction in the frequency of inoperability of the safety grade Control Room air conditioning units and improved environmental conditions observed in the Control Room during the summer of 1983. The licensee submitted appropriate changes to the TS to reflect appropriately revised surveillance requirements for the Control Room ventilation system. These changes were issued (amendments 89 [Unit 1] and 70 [Unit 2]) on December 30, 1983.

(Closed) Unresolved Item (317/82-05-01) Chemical and Volume Control System Process Radiation Monitor and Boronmeters out of Service since 1978 and 1981, respectively. The licensee returned these monitors to service for both units during calendar year 1983. During Control Room tours, the inspector has observed that they have continued to maintain the monitors. The NRC will continue to monitor the licensee's prioritization of maintenance during routine inspection and during follow up of Unresolved Item (318/82-05-06), Check Timely Initiation of Repair of Safety-Significant Failures.

(Closed) Unresolved Item (317/83-11-02) Revision of Technical Specification Snubber Tables. The licensee applied for a TS change to correct the snubber tables. Appropriate changes were issued by the NRC (Unit 1 Amendment 89, Unit 2 Amendment 70) on December 30, 1983.

(Closed) Unresolved Item (317/83-13-02) Verification of Unit 1 Dresser Pressurizer Safety Valve Ring Settings. The licensee verified the blowdown ring settings during the fall, 1983 Unit 1 outage. The inspector reviewed MRs M-83-407 and 408 documenting completion of this verification by a vendor technical representative in accordance with a specific POSRC approved procedure (Blowdown Ring Inspection of Safety Valves, POSRC Meeting 83-407). The blowdown rings were adjusted within specifications.

(Closed) Unresolved Item (317/83-07-05) Post Trip Review Procedure Recommendations. The licensee has revised their post trip review procedure, CCI 118B, Post Trip Review Requirements, December 1, 1983. The inspector verified that this procedure addresses those items addressed in Inspection Report 83-07.

(Closed) Performance Appraisal Section (PAS) Item (317/82-01-54) Inadequacies in Record Keeping of License Candidate Participation in On-Shift Training. The inspector reviewed the on-shift training records for selected personnel and found the records to be complete. This item is closed.

(Closed) Performance Appraisal Section (PAS) Item (317/82-01-55) Requalification Examinations did not cover Title 10, Chapter 1, Code of Federal Regulations. The inspector reviewed the content of recent requalification examinations and noted that this area is now being covered.

(Closed) Inspector Follow Item (317/83-30-01) Corrective Actions for Loss of Shutdown Cooling due to Hydrostatic Test. This item had been left open pending NRC review of the licensee's investigation and corrective actions. The inspector reviewed Calvert Cliffs Event Report 83-20 which addressed this issue. The analysis was thorough. The POSRC directed that:

(a) Hydrostatic Test Procedures will be required to include a list of all affected instruments.

(b) AOP-11, Loss of Shutdown Cooling be revised to provide guidance for cases when the vessel head is detensioned and the pool seal is in place and to require that Radiation-Control be notified for this type of event to investigate radiological conditions.

(Open) Unresolved Item (317/83-21-01) Revision of STP to Require Firmly Connecting Halon Fire Suppression Bottles. The licensee had committed to revise Surveillance Test Procedures to prevent a recurrence of loosely connected Halon Fire Suppression bottles. Although the bottles were discovered loose in August, 1983 and the Inspection Report documenting the commitment issued in October, 1983, the applicable Surveillance Test Procedure had not been revised as of January 27, 1984. The licensee's Fire Protection Inspector thought that this item had been resolved. The only licensee mechanism which was in place to ensure completion of commitments made to the NRC during the course of inspections had not been updated since this report was issued. The latest update was issued on August 19, 1983. The inspector discussed this item with the Licensing and Safety Engineer responsible for maintaining the commitment list. The Engineer stated that no predefined interval for updating the list existed. The current practice was to initiate an update upon a specific request by management. He stated that all items contained in inspection reports are incorporated when a revised list is generated, and that this would have eventually resulted in revision of the appropriate procedure. The inspector recommended that the licensee establish a predefined interval for updating and distributing the commitment list. The Fire Protection Inspector initiated a procedure change the same day. The inspector reviewed the revised draft STP which contained a note requiring checking the connections tight.

(Closed) Inspector Follow Item (317/83-27-01) Initiate Replacement Program for GE Type HFA Relays. Following discussions and a site visit by a vendor technical representative, the licensee has decided to replace the HFA relays with the new type 1E Century Series, mentioned in Information Notice 82-13, versus initiate a coil replacement program. Such a replacement program would have required additional periodic replacement of coils. The inspector reviewed a purchase order revision dated January 20, 1984, ordering the new relays. In addition to 29 safety related applications the licensee has decided to replace 38 non-safety related relays, principally in normally energized applications.

(Closed) Violation (317/80-26-02) Failure to Secure Charging Pumps During Special Test. The licensee responded to this item in a letter dated March 16, 1981. The event was reviewed with the operators involved and all licensed operators were made aware of the event. In addition, the licensee submitted a revision to the Technical Specifications (approved in Amendments 59 and 41 on November 4, 1981) to specifically require isolation of the charging flow paths as a Limiting Condition for Operation, thus amplifying the Surveillance Requirement.

(Closed) Unresolved Item (317/83-18-01) Page Check one Controlled Calvert Cliffs Operating Manual (CCOM). The inspector discussed this item with the Operation Clerk. A complete check of the Shift Supervisor's copy of the CCOM was performed in 1983 (AOPs, EOPs, OIs). The clerk stated that no temporary changes (CCOM changes) were found to be missing, although because of the condition of some of the entries the changes were reentered by the clerk in many cases. In addition, the licensee has implemented a review program for the CCOM. This program is supervised by a licensed Senior Operator and has 5 licensed operators assigned full time. The program has resulted in more timely incorporation of CCOM changes into procedure revisions, in addition to improving the readability and useability of the procedures.

(Closed) Inspector Follow Item (317/83-07-04) Revise EOP1 Reactor Trip Procedure. This item concerned an erroneous statement in EOP1 to the effect that the Post Trip review computer printed out on the utility typewriter. (In fact the print out is on the In-Core Typewriter.) EOP1 has been revised (Revision 13) to require that the operator demand the Post Trip Review print out without specifying a printer. As noted in the subject inspection report the Sequence of Events prints out automatically on the Utility Typewriter.

(Closed) Inspector Follow Item (317/82-27-01) Clean Up #21 Fuel Oil Storage Tank Valve Pit, Diesel Generator Rooms, and the Main Steam Piping Penetration Rooms. During facility tours the inspector noted that the licensee has made improvements in the housekeeping in these areas. During the current inspection, operations personnel completed a thorough cleaning of the Diesel Generators, Steam leaks in the MSIV Rooms were corrected during the recent outages, and the inspector noted that the piping in the Fuel Oil Storage Tank Pit was not under a fuel oil/water mixture.

(Closed) Unresolved Item (317/82-26-02) Procedural Inconsistencies Regarding Actions to be Taken Following a Seismic Event. The inspector reviewed Operating Instruction OI-46, Revision 3, and Emergency Response Plan Implementing Procedure (ERPIP) 3.1, Revision 10, Change 1 to verify resolution of identified inconsistencies. The inspector noted that use of a template has been discontinued, OI-46 appropriately addresses plant actions following a seismic event and ERPIP 3.1 addresses associated notification procedures.

(Closed) Inspector Follow Item (317/82-26-06) Operator Awareness of Alarm Status. The event discussed in the subject inspection report appears to have been an isolated event. Since the event the inspector has noted a generally high operator level of awareness of plant alarm status in the Control Room.

(Closed) Violation (317/82-15-02) Inappropriate Capping of Containment Pressure Sensing Lines. The licensee stated that metal tags have been placed on the pipe ends on both units identifying their function. A walkdown was performed on Unit 1 which showed that only the Containment pressure sensing lines were threaded as discussed in the violation. A similar walkdown is scheduled to be performed on Unit 2 during the Spring 1984 outage. Facility Change Request (FCR) 83-20 has been performed on Unit 1 which added a collar and pipe extension (unthreaded at exposed end) to each Containment pressure sensing line. A similar change is scheduled for accomplishment on Unit 2 at the first available outage. The responsible engineer verified that the necessary materials were available and the work package prepared. The inspector confirmed that Operating Procedure - 6 "Pre-Startup Checkoff", Revision 27 (applicable to both units), requires a check, prior to startup that caps are not installed on the Containment pressure sensing lines and the Hydrogen Sampler Return Line. The inspector also confirmed that the licensee completed short term training on the sensing line capping event and that the licensee's General Orientation Training Program for visitors and new employees provides direction that safety related activities must be accomplished under properly approved procedures.

(Closed) Unresolved Item (318/83-02-07) Train Operations Personnel in Startup Physics Testing Procedures Prior to Next Refueling Outage. The licensee (Nuclear Fuel Management personnel) conducted physics testing training during the 1983 Requalification Training Program. A full day lecture was conducted on various dates in March and April, 1983, prior to the start of the Unit 1 Refueling Outage (Fall, 1983). The inspector reviewed the lesson plans and noted that they addressed the weaknesses identified in the subject item. The licensee also conducted specific pre-shift briefs for Operations Personnel during the Unit 1 Startup Test Program. The inspector discussed the scope of these meeting with a Shift Test Engineer. He stated that the meetings addressed the testing to be performed, any TS Special Test exceptions to be invoked, the reason for the exceptions, and who would be performing the testing.

(Closed) Inspector Follow Item (317/83-15-01) Check of Saltwater Valve Automatic Opening Feature to Be Added to Preventive Maintenance (PM) Program. The inspector examined PM 1-52-I-RQ2-37 (revised September 30, 1983). This revision incorporates verification of proper functioning of the Saltwater Flow Control Valves in response to the rooms' temperature controllers.

(Closed) Violation (318/80-02-06) Failure to Follow Operating Instruction Requirements for 2 Valve Isolation of CVC Deborating Ion Exchanger By Using an Unspecified, Single Valve. The licensee responded to this item in letters dated May 14 and August 5, 1980. Corrective actions included, or discussed, for this item included the (then) recent addition of another licensed Senior Operator on shift. This individual was tasked to ensure strict procedural adherence. In addition, a memorandum from the Nuclear Power Manager reiterated the importance of procedure adherence and timely corrective actions for procedure changes and revisions. Since 1980, several changes have been made in the licensee's methods for implementing procedures. Non-licensed operators are now required to have procedures in hand when performing evolutions. Procedure change mechanisms are in place which allow temporary changes to be made in a convenient fashion. The inspector concluded that these actions improved operator adherence to procedures. Although occasional, additional instances of failure to follow procedures have occurred, the existing practices of procedure adherence at Calvert Cliffs have changed considerably since this violation. This area is examined routinely by the NRC.

(Open) Inspector Follow Item (317/82-18-04) Review Licensee's Corrective Actions to Prevent Opening a Disconnect Under Load. The licensee has placed large, conspicuous warning signs on the installed manual disconnects and on the fronts of the various breakers feeding disconnects. These signs caution operators to ensure that the supply breaker is open prior to operating a disconnect and note that an alternate feed exists for the breakers in question. The licensee has also revised the system operating instructions to require use of OI-27 when operating a particular system's disconnects. OI-27c, 4.16 KV System, Revision 7 requires as initial condition (a) The breaker associated with the disconnect to be operated is open, and (b) the breaker handswitch associated with the disconnect to be operated is in PULL-TO-LOCK. The procedure requires a local check of the breaker associated with the disconnect to ensure it is open, and a verification that the handswitch is in PULL-TO-LOCK. The disconnect interlock key is required to be turned a full 180° and removed prior to opening the disconnect. (This action trips the supply breaker if its still closed.) All operators were required to read the Personnel Incident Report detailing improper operation of the disconnect. They also receive training (including performance or walk through for disconnect operation).

Notwithstanding the above actions, another improper 4 KV disconnect operation occurred on December 13, 1983 (LER 83-074). An operator mistakenly operated the disconnect for #13 Saltwater (SW) Pump when he had been directed to open the disconnect for #13 Service Water (SRW) Pump. Fortunately, the breaker interlock worked this time, thus the only effect on the plant was a momentary (about 2 minutes) loss of a Saltwater subsystem. The inspector reviewed the Personnel Incident Report (dated February 13, 1983) for this event. The report was in required reading for all operators. The Auxiliary Building Operator stated that he was told to disconnect #13 SRW pump from #14 4 KV Bus. The operator checked the Control Room handswitch in PULL-TO-LOCK, checked #13 SRW pump disconnect to 14 Bus, checked the #13 SRW pump breaker open and then proceeded to #13 SW pump disconnect and opened the same. The operator's suggestion to prevent recurrence called for paying closer attention while performing duties and checking name plate and equipment numbers a second time before performing the evolution. GSO Standing Instruction 83-13 was issued on December 20, 1983. Manual operation of 4 KV disconnect now requires performance by two people who as a minimum are qualified Turbine Building operator. Prior to operation of the disconnect the person performing the operation must demonstrate to the observer that he is operating the correct disconnect and the procedures of OI-27c are being followed.

The licensee had initiated a facility change (FCR 82-40) to install arc chutes in the 4 KV disconnects. The inspector reviewed the status of this FCR, noting that approval to order the equipment had been received. The parts were ordered on February 7, 1984. This will eliminate the potential for personal injury in the event a disconnect is opened under load and the breaker interlock feature malfunctions (as occurred on August 4, 1982). This item will remain open pending installation of the arc chutes.

(Closed) Unresolved Item (318/83-27-01) Housekeeping Deficiencies in the Service Water Pump Room. During this inspection the licensee performed a ceiling to floor cleanup of the Unit 1 Service Water Pump Room and scheduled a similar cleanup of the Unit 2 SRW Pump Room. The inspector noted that the material and debris which were present in the Unit 2 room during Inspection 83-27 (following Auxiliary Feedwater System Modifications) had been removed. Housekeeping conditions will be examined on a routine basis in future inspections.

(Closed) Unresolved Item (317/82-27-02) Reportability of Inoperability of Equipment Required by Appendix B, Environmental Technical Specification (ETS). The inspector had been concerned that inoperability of equipment in the ETS was not required to be reported to the NRC. If the equipment had been required by Appendix A Technical Specifications a 30 day or shorter report would have been required. The Licensee Event Report requirements contained in the Technical Specifications have been superseded by 10CFR50.73. This item is no longer appropriate considering the revised regulation, which is applicable to both Appendix A and Appendix B Technical Specifications.

(Closed) Inspector Follow Item (318/83-30-02) Resolution of Software Deficiency of TSC Computer. This item concerned discovery that the TSC computer was not functioning following a plant trip, therefore not capable of being used for analysis. Additional inve' igation by the licensee revealed that there was no software deficiency. The TSC computer alarm had been reset by operations personnel. In order to properly clear the TSC alarm however, a bootstrap procedure must be followed. The licensee issued an instruction "Annunciator L15 Reset and TSC Computer Operators Guide", to bootstrap the Computer. This guide was approved by Shift Supervisor Caution Tag C-84-18. The licensee is in the process of creating a permanent procedure to implement the guide.

(Closed) Unresolved Item (318/82-27-01) Improper Tagging - Removal of 2-RV-200. The licensee has fabricated spool pieces with openings greater that 1.3 square inches. These are bolted into the gap between the pressurizer relief valves and the pressurizer when credit is being taken for this path for MPT protection during cold shutdown. The spool pieces were used during the latest refueling outage.

(Closed) Inspector Follow Item (317/83-13-04) Licensee to Establish Proper Administrative Controls for the PASS Liquid Return Valve (SV-6529). During the referenced inspection the NRC noted that proper administrative controls, as committed in the licensee's safety evaluation, had not been implemented. Specifically, although Surveillance Tests required verification of fuses removed there was no required check of the correct key-locked status of the solenoid valve. The violation identified in this report was a direct result of failure to properly implement these specific administrative controls. Further NRC review of Administrative Controls associated with SV-6529 will be accomplished as a part of the larger issue described in Section 6 of this report.

(Open) Unresolved Item (317/81-08-03) Inadvertant Discharge of Fuel Oil to Bay. When this item was reinspected (Report 317/83-09) licensee corrective actions were verified with the exception of installation of sight glasses for the yard oil interceptors. The licensee decided not to install sight glasses. The inspector reviewed completed Facility Change 81-106. This change had cut a 12"x12" hinged plate opening in the #11 Fuel Oil Tank Sump Interceptor and the Diesel Generator Room Oil Interceptor. These access openings would allow access to the interceptors. The oil/water interface can be verified using a stick and a water sensitive paste. The inspector questioned the licensee concerning implementation of a check of the interceptor water seals. A quarterly Preventive Maintenance item (53-1-0-Q) existed to pump down the yard oil interceptor as needed, however, no similar check of the other interceptors existed. A monthly PM did exist (53-2-0-M) requiring a check of the diesel oil and fuel oil unloading station interceptors. The check was to verify that the outer tank was empty and the weir valves shut. Operators were unsure what the PM meant when questioned by the inspector. Weir valves exist on the transformer pits to prevent draining oil into the yard drains. A separate PM addresses these valves. There is a locked shut valve from the #11 Fuel Oil Tank embankment to the Fuel Oil Unloading Station interceptor. There are external tanks for both fuel oil interceptors (pumped quarterly) and a concrete vault in which the interceptors are placed. The licensee and inspector were unsure whether the PM applied to the tank, vault, or both. When checked by the inspector both interceptors, associated piping valving and heat tracing were completely submerged in an oil/water mixture. The licensee committed to clarify the PM's for the interceptors and establish a check of their operability (as previously committed) by measuring the water/oil interface level.

(Open) Inspector Follow Item (317/83-07-01) Restoration of Fire Barriers. During the inspection period the inspector noted that a vertical fire barrier between safety related cable trays ZF 2AE77 and ZG 2AE73 in the 45 foot elevation of the Unit 2 West Electrical Penetration Room still was broken and missing. The inspector pointed this out to the Fire Protection inspector who stated he would initiate corrective action. He noted that some barrier repairs had been accomplished on Unit 1, and he suspected that the barrier in question may have been confused with a Unit 1 barrier.

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.

The inspector reviewed a new plant policy (Operations Administration Policy 84-02) allowing plant operators to tighten valve packing glands and mechanical joints on a limited number of manually operated valves. This policy was initiated to reduce the number of maintenance work requests and correct minor problems as they are found. The current policy, as written, does not provide a mechanism to assure recurring problems are evaluated and adequate repairs made. The licensee revised the policy to require that a maintenance work request be initiated on recurring problems.

On January 10, 1983 the inspector noted that the High Pressure Safety Injection (HPSI) Auxiliary header pressure indicator was reading below 0 psig. The HPSI main header indicator was reading about 50 psig (corresponds to RWT pressure head). Because the two headers were cross-connected and should have read the same pressure, the inspector questioned the Control Room operator about the reading. The valve lineup to the Auxiliary HPSI header was verified to be correct. A HPSI pump was started and the CRO noted that both instruments responded, however a 60 psid offset was observed between the instruments. An MR (0-84-228) was written to investigate the apparent drift of the Auxiliary HPSI header pressure indicator.

On January 10, 1984 the inspector noted that the Unit 2 Motor Driven Auxiliary Feedwater (AFW) Pump flow control valves were in the automatic mode, set at 160 gpm. The corresponding Unit 1 valves were in automatic set at 200 gpm. As discussed in NRC Inspection Report 83-31, the licensee had committed to operate the motor driven AFW train in manual flow control, set at less than 25% of full open. (This was to preclude pump run out at the lowest expected pressure following a Main Steam line break, assuming no operator action for 10 minutes. As demonstrated in system startup testing run out is possible under the conditions which existed on January 10, 1984.) The inspector discussed the situation with the Plant Superintendent who stated he would take corrective action. Surveillance Test Procedure 0-5 and Operating Instruction 32 were revised to require leaving the controller in manual. During subsequent Control Room tours the inspector observed that these valves were positioned as committed to the NRC.

b. System Alignment Inspection

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

--Containment Isolation Valves and Service Water to Containment Coolers in Unit 1 27 foot West Penetration Room checked on January 24, 1984.

--Unit 1 Hydrogen Purge/Containment Vent System checked on January 4,1984.

--Unit 1 High Pressure Safety Injection System checked on January 4, 1984.

--Unit 1 Service Water and Saltwater Systems in U1 Service Water Pump Room checked on January 19, 1984.

--Saltwater System in Unit 1 and Unit 2, checked on January 11 and 12, 1984.*

*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.); instrumentation lineup and operability; and valve position/locking (where required) and position indication, and availability of valve operator power supply. Results of this inspection are discussed in paragraph 11.

c. Biweekly and Other Checks

The inspector observed shift turnovers; boric acid tank samples and tank levels were compared to the Technical Specifications; and the use of radiation work permits and Health Physics procedures were reviewed. Area radiation and air monitor use and operational status was reviewed. Plant housekeeping and cleanliness were evaluated.

During plant tours the inspector noted that the licensee had made progress towards improving general plant housekeeping, cleanliness, and material conditions. A general cleanup of the Turbine and Auxiliary Building was performed in early January. The 45 foot Turbine Building elevation was cleaned and painted. The inspector observed that steam leaks had apparently been repaired in the Main Steam Penetration Rooms as indicated by reduced temperature, humidity, and noise levels in said rooms. A program was in place to repaint the containment interior walls in both units' 27 foot East Piping Penetration rooms. In general, the housekeeping cleanliness condition of the Plant seemed to be significantly improved. Several problem areas were noted to the Plant Superintendent during the inspection, such as the condition of the Intake Structure (general debris and scaffolding,etc.), during the week of January 9, 1984. This area was cleaned up later in the report period.

During a check of the Auxiliary Feedwater (AFW) instrumentation in the Cable Spreading Rooms on January 6, 1984, the inspector observed an anomalous indication between Units 1 and 2 Steam Generator greater than AFW Pump Discharge Line Differential Pressure indicators. This instrumentation is used in the AFW feed line break logic. Unit 2 data was consistent on all 4 channels at about -3%, and Unit 1 was consistent between the channels at 12% (range on the meters is -25 to 100%). Because both units were at full power and the instrumentation sensing the same relative conditions, the inspector questioned the licensee regarding the indications. The General Supervisor-Operations stated that the condition would be investigated. Possible explanations included leaking check valves between the discharge line and the Steam Generators, the spinning of the Unit 2 AFW pump steam turbines due to leaking diaphragm valves (newly installed), or possible installation or calibration errors. (The AFW system under went major modifications in 1983.) MR 0-84-117 was initiated to investigate the anomalous indication. Initial review did not reveal any obvious cause for the anomalies. This item is unresolved (317/84-01-03) pending determination of the reason for the apparent pressure differences between the units.

During a plant tour on January 20, 1984 the inspector observed that a half full bucket of oil had been placed over the suction grate for the emergency suction line for the #21 Fuel Oil Storage Tank tornado enclosure. This Seismic Category I Structure serves as a dike for the storage tank. In the event of tank failure, suction for the diesel generators can be taken from the concrete structure itself. The inspector questioned the licensee concerning the placing of the oil bucket. The suction path was probably not jeopardized in that in the event of tank failure, the bucket would probably float off or be displaced from the emergency suction. The General Supervisor-Operations stated that he was unaware of any reason for placing the pail over the suction (a caution sign warning personnel not to place liquids into this grate is already in place). He stated that the pail would be removed and an additional sign placed directing that the emergency suction path not be blocked. A revised sign with an appropriate Caution Note was installed during the current inspection.

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

--Tagout 4350, #21 Saltwater Pump checked on January 25, 1984.

--Tagout 4367, Unit 1 Containment Purge valves checked on January 25, 1984.

--Tagout 4365, Unit 1 Hydrogen Purge/Containment Vent System checked on January 4, 1984.

--Tagout 3872, #12 Saltwater Header for Heat Exchange Bulleting checked on January 18, 1984.

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

--M-10-84, Miscellaneous Waste Monitoring Tank released on January 17, 1984.

--V-007-84, Unit 2 Containment Vent released on January 14, 1984.

--The inspector reviewed the following Radiation Control Logbooks for the period January 1-9, 1984: Auxiliary Building 69', Auxiliary Building 10', Outside Auxiliary Building 27', Outside Auxiliary Building 5', and Outside Auxiliary Building 45'. Primary and secondary chemistry logs for January, 1984 were reviewed.

4. Review of Events Requiring Prompt Notification to the NRC

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

--At 1:47 p.m. on January 21, 1984, with Unit 1 operating at 100% power, all reactor trip breakers opened for no apparent reason, causing a reactor and turbine trip. Immediately prior to the trip, instrument technicians had been performing a surveillance test (M-210B-1) of the RPS logic trip matrices. At the time of trip, however, the technicians were at a pause point in the procedure, indicating that their actions did not cause the trip. Following the trip the logic martrix test was repeated two times to determine if it could have caused the trip. Additionally trip matrix power supply outputs were checked, and power supplies were deenergized one at a time to see if transients could be induced which would affect the alternate power supply. No problems were identified. The plant was restarted on January 28, 1983 following a licensee post trip review and meeting of the Plant Operations and Safety Review Committee (POSRC). The inspector subsequently reviewed the associated computer printouts, the licensee's post trip review documentation, and RPS logic matrix and test circuit design. As of February 1, 1984, the licensee was performing a second post trip review. No definite cause was found for the event. The NRC will review the licensee event report upon issuance (317/84-01-05).

--At 9:50 a.m. on January 12, 1984, with #12 Diesel out of service for modifications, #11 Diesel apparently failed a surveillance test (did not reach 900 RPM in the required time following engine start). The governor linkage was adjusted, and the #11 Diesel was satisfactorily tested by 10:45 a.m. The #11 Diesel again apparently failed to meet its surveillance test requirement during a start at 5:01 p.m. later on January 12. Subsequent investigation showed that the timing device being used was not operating properly and that #11 Diesel was operable.

--During the performance of Surveillance Testing on February 3, 1984 the licensee observed that the discharge damper (2HVAC-5406) for the ECCS Pump Room Exhaust Fan #21 was not opening fully. The fan was apparently forcing the damper slightly open from its closed position. The redundant #22 Exhaust Fan and damper were operable. Licensee investigation revealed that a supply valve in the damper's instrument air path (2-IA-554) was closed. This valve had been closed on December 20, 1983 following discovery that the ECCS Exhaust Filter bypass damper was sticking. This action should have resulted in the filter bypass damper (5408A) being failed shut and the face damper (5408) being failed open, until action could be taken under MR 0-83-9136 (initiated the same day) to repair the bypass damper operation. Dampers 5408 and 5408A do in fact receive air through 2-IA-554 and were in the correct position, however so does the 5406 damper. A recently issued Instrument Air drawing (OM 454, Revision 0, revised June 22, 1983) had the incorrect valving arrangement to the damper actuators, showing air to 5406 as passing through a (non-existent) valve numbered 2-IA-555. The drawing also had the incorrect identification of the isolation for the 5407 damper (discharge for the redundant exhaust fan). The licensee capped the line going to the filter bypass and face dampers, thus failing the dampers in the correct position, ' id then restored Instrument Air to the exhaust fan discharge damper. The inspector discussed the event with operators and examined the piping installation and drawings. (The line to 5406 SV was somewhat obscure, and, in addition, the valve labeling for 2-IA-554 referred only to the 5408 and 5408A dampers. This labeling and the OM drawing clearly contributed to the isolation of air to 5406.) Because the #21 exhaust fan was inoperable longer than the 7 days allowed by TS 3.7.7.1.a, a licensee event report is required per 10CFR50.73 for a condition prohibited by of the Technical Specifications. Additional licensee actions with respect to this event will be examined (318/84-01-02) following receipt of the written report.

Prior to the issuance of this report, this event was further examined during the February 15 - March 13, 1984 inspection period (Inspection Report 317/84-03, 318/84-03 dated March 26, 1984, Section 6.b) and determined to be a licensee identified violation meeting the criteria specified in Section IV A, Appendix C, 10 CFR 2. Therefore, a Notice of Violation was not issued.

5. Observation of Physical Security

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

No unacceptable conditions were found.

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			
83-62	11/29/83	12/29/83	Post-Accident Monitoring Instrumentation Channel X Inoperable
83-63	11/30/83	12/29/83	#11B Safety Injection Tank Inoperable
83-67	12/04/83	12/30/83	Saltwater Inlet Control Valve 1-CV-5173 Inoperable

LER No.	Event Date	Report Date	Subject
Unit 1			
83-69	12/21/83	1/19/84	Response Time of Trip Circuit Breaker Undervoltage Devices Slower than Allowed by TS
83-71	12/10/83	1/09/84	Pressurizer Pressure Decreased to 2180 PSIA
83-72	12/22/83	1/05/84	Reactor Protective System Channels A and C for Reactor Coolant Flow Inoperable
83-73	12/16/83	1/05/84	Excessive Leak Rate Past the Containment Personnel Air Lock Outer Door
83-74	12/13/83	1/12/84	Flow Lost in Saltwater Subsystem when Operator Operated the 4KV Disconnect on Operating Saltwater Pump (See Paragraph 2)
83-75	12/27/83	1/27/84	RPS Channel D for High Power and Thermal Margin/Low Pressure Inoperable
83-76	12/30/83	1/26/84	AFW Pump Inoperable
83-77	12/31/83	2/2/84	Oyster Samples Collected During December, 1983 showed Ag-110m to be 113±6 pCi/kg (wet)
83-78	12/29/83	1/27/84	Pressurizer Level Decreased Below 133 Inches Three Times
Unit 2			
83-67	12/08/83	1/06/84	#22 Charging Pump was out-of-service; 23 Charging Pump Discharge Relief Valve Lifted
83-68	12/17/83	12/29/83	Dose Equivalent I-131 was 1.413 Micro-Curies Per Gram
83-69	12/19/83	12/29/83	Reed Switch Position Indication Inoperable
83-70	11/25/83	12/22/83	Pressurizer Level Decreased to 116 Inches While Loading Main Turbine
83-71	12/19/83	1/18/84	Power Dependent Insertion Limit for Group 4 Rods Inoperable
83-72	12/17/83	1/12/84	#21 Main Steam Isolation Valve Inoperable
83-73	12/20/83	1/19/84	RPS Channel D for Steam Generator Low Pressure Trip Inoperable
83-74	12/23/83	1/19/84	AFW System Inoperable
83-75	12/10/83	1/09/84	CMI Inoperable
83-76	12/27/83	1/26/84	Two CEAs Dropped Into Core

83-77	12/21/83	1/19/84	Leak in a Charging Header Drain Line

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.

--2/83-38 Inoperability of the ECCS Pump Room Exhaust Charcoal Filters. This LER was initially inspected during Inspection Report 318/83-21. The licensee was requested to submit a revised report. A revised report was submitted on January 13, 1984. This report appropriately corrected the cause description and corrective action portion of the LER.

--1&2/83-64 HPSI Flow Balance Test. During shutdown of Calvert Cliffs Unit 1, licensee had measured the HPSI injection leg flow and found that several measurements did not conform to the value of 170 ± 5 gpm per Technical Specification (TS) 4.5.2.h. Several HPSI injection throttle valves were subsequently found to have stem travels that required adjustment. Flow tests were again performed with acceptable results. This situation was also found to exist at Unit 2. The Unit 2 HPSI injection throttle valves were also adjusted to provide the required stem travel although no flow test was performed in that Unit 2 was in operation. The discovery of the HPSI flow imbalance was reported by the licensee for Units 1 and 2 as LER 83-64/3L.

On January 13, 1984 the inspector met with the licensee to discuss LERs 83-64 and to review associated stem travel and flow measurement data. The stem travel limit switch adjustment is made per FTE-47, Revision 2, "Electrical Motor Operated Valve Test Procedure". Section VI of FTE-47 addressed "Special MOV Limit Switch Settings" which specifically reference the adjustment of the HPSI flow leg injection throttle valves MOV-616, 617, 626, 627, 636, 646, and 647 for Units 1 and 2. This procedure references adjustment of stem travel with a flow of 170 ± 5 gpm (if possible) or adjustment within ± 1/32 inch of the most recent stem travel for which flow was observed. Stem travel adjustment for Unit 2 was undertaken as documented in MR-E83-427A which showed stem adjustment data under no flow conditions. The largest adjustment was undertaken for valve 2-MOV-636 (.297 inches) while the smallest adjustment was undertaken for 2-MOV-616 (.078 inches). Valves 2-MOV-637 and 647 were found to be within the adjustment range of 1/32 inch (.031).

Maintenance Requests E-83-339 and I-83-316 were reviewed concerning adjustment of the Unit 1 HPSI injection leg flow throttle valves. In the case of Unit 1, the adjustment process was made with the benefit of HPSI flow. As with case of Unit 2, several of the Unit HPSI injection leg throttle valves required adjustment and in some cases readjustment.

It appears that very small stem travel adjustments are required to maintain HPSI injection leg flow to within the ± 5 gpm range specified by TS 4.5.2.h. Accordingly, stem travel adjustment may be the real issue. The following course of action was discussed, and agreed to, by the licensee:

(1) Inadequate experience appears to be available regarding HPSI injection throttle valve stem travel and flow adjustment. The previous flow test had been performed during initial preoperational testing. The licensee will perform HPSI injection leg flow measurements on each unit during refueling outages. Results of these tests will be reviewed.

(2) LER 83-64/3L were inadequate in that they did not address the issue of injection throttle valve stem travel. The licensee resubmited the LER on January 24, 1984, and corrected this problem.

(3) The HPSI injection leg flow uncertainty, ± 5 gpm seems too small. The licensee will pursue this item with Combustion Engineering. These actions will be followed by the NRC (317/84-01-01).

--LER 1/81-79 and 2/81-47, Back flooding of Service Water Pump Rooms. This LER addressed the discovery (during A/E review of IE Bulletin 79-01B) that the drains from these rooms lacked back flow protection from the Turbine Building. Temporary back flow protection (in the form of inflatable plugs) was installed in the rooms. The inspector reviewed completed Facility Change 81-1062, and examined the installation of permanent drains in these rooms. These LERs are closed.

--On January 13, 1984, the licensee discovered that the Post Accident Sampling System (PASS) Return to Reactor Coolant Drain Tank Containment Isolation Valves (1-SV-6529) was open. Technical Specifications (TS 3.6.4.1) allow this valve to be open but only under administrative controls. The valve's position indication light lenses (open and closed) were discovered reversed, causing a false closed indication. The licensee stated that the valve had been last checked shut following installation of control fuses on January 3, 1984, by an operator verification that the green (closed) indicating light was on. This valve is operated from the local PASS control panel by a key operated switch with key removal permitted in the open or shut position of the switch. The same valve had been verified closed on January 1, 1984, as a part of a monthly surveillance test (prior to the fuse installation) by an operator verification that the fuses were removed and the key switch was in the closed position. The chemistry, maintenance, and operation groups each maintained keys under their control which would allow 1-SV-6529 to be opened. The licensee interviewed personnel who had used this key type during the period of January 3-13, 1984. No reason was found for leaving 1-SV-6529 in the open position or for the lens caps to be reversed. They suspected the lens caps may have been inadvertently switched during a check of light bulbs in the position indicators. The inspector reviewed Licensee Event

Report (84-01) which the licensee submitted on February 10, 1984. The licensee stated in the report that the following corrective actions would be taken:

(1) Keys that would operate 1-SV-6529 and other similar Containment isolation valves have been removed from the control of the chemistry and maintenance groups;

(2) a facility design change will be made such that key operated Containment isolation valve key switches will be keyed uniquely from all other plant equipment;

(3) a facility change will be made that for key operated Containment isolation valves key withdrawal will not be permitted when the key switch is in the open position; and

(4) the administrative requirements for operation of 1-SV-6529 and similar valves will be reviewed with plant chemistry, operations, and electrical and controls personnel.

The NRC had previously inspected (Section 10 of Inspection Report 83-13) the administrative controls for SD-6529. The valve in question had been changed from a Oxygen Sampling System valve with a Containment Isolation signal to a PASS valve with no automatic close signal. The solenoid (Dragon Model 10180-1) which operates the valve had been determined to be not qualified for its intended use during IE Bulletin 79-01 reviews. The licensee had identified the lack of qualification of this and other Dragon solenoids in correspondence to the NRC (letters dated February 26, 1982 and May 10, 1983). Replacement is scheduled for the Spring of 1985 (Unit 1) and Spring of 1984 (Unit 2).

The original FCR Safety Evaluation required removal of fuses for SV-6529 as a dual means of administrative controls to ensure the valve would not open (in addition to the key lock switches). The licensee decided in 1983 that it was not prudent or necessary to remove fuses to ensure that the valves remained closed. The licensee stated that their primary motive for not wanting fuse removal to be a part of the administrative controls was implementation difficulty (i.e., difficult to ensure proper size fuses would be available in an emergency). Similar valves only require key switch administrative controls.

The licensee performed a revised Safety Evaluation for FCR 80-1008 to allow restoration of the control power to SV-6529 (approved December 14, 1983). The licensee also discussed the change with the NRR LPM because the NRC Safety Evaluation for Amendment #87 also addressed removal of control power. The NRC agreed there was no need for an amendment in that the Technical Specifications were not affected and the change was evaluated in accordance with 10CFR50.59.

The inspector reviewed the revised Safety Analysis (FCR 80-1008 Supplement 28) for the administrative controls for SV-6529 and FCR 83-1002 to replace existing Dragon valves with valves which are environmentally and seismically qualified. SV-6529 apparently opened when FCR 1008 Supplement 28 was being implemented on January 3, 1984. A careful examination of the key switch and position indication on January 3 should have determined that the valve was indeed open.

Between 2:00 p.m. and 2:03 p.m. on January 23, 1984, with Unit 1 at 100% power licensee chemistry personnel improperly opened two Containment isolation valves (1-SV-6540G and 1-SV-6507G) in a penetration used for returning gas samples to Containment. The evolution was associated with a check out of the PASS. TS 3.6.4.1 does not allow these valves to be opened during Mode 1-4 operation.

Due to an apparent licensee oversight and/or philosophy that the PASS would not be operated in Modes 1-4 (at the time the PASS system was declared operable), the licensee did not request a Technical Specification change which would allow these valves to be opened under administrative controls. These valves must be opened to operate the PASS along with liquid return line valve 1-SV-6529 discussed above.

The chemistry personnel first obtained permission from the Control Room Operators prior to opening the valves. The Shift Supervisor thought that the only valve to be opened would be 1-SV-6529. Chemistry personnel did not realize that valves 1-SV-6507G and 1-SV-6540G were not permitted to be opened by TS's. Shortly after the valve openings, a Control Room Operator realized that the actions were not proper and ordered the valves to be closed.

Licensee failure to maintain proper controls over the positioning of valves 1-SV-6529, 1-SV-6507G, and 1-6540G is a violation (317/84-01-08).

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.

--M-83-834, Post Maintenance Operability for #13 AFW Pump, observed on January 10, 1984.

--MR-E-83-492, Replace Front Frame Assembly TCB-3, observed on January 4, 1984.

--M-84-009, Bulleting of #12 Service Water Heat Exchanger, observed on January 18, 1984.

During the Saltwater System lineup verification on January 12, 1984 the inspector observed that two Deficiency tags for excessive pump packing leak off had apparently been in place for a protracted period of time. Neither pump appeared to have excessive leakage. One of these (MR-0-83-7375) concerned the #11 Saltwater Pump. The packing leakage was not excessive. Inspector review of the MR Tracking System Status revealed that the particular MR (0-83-7375) had been completed. The mechanics performing the work apparently had not removed the deficiency tag. The Senior Control Room operator had the particular tag removed. The inspector questioned the Plant Superintendent concerning whether or not any sampling or periodic surveillance program existed to verify that posted deficiency tags were still valid. Because no such program existed the inspector recommended implementation of a suitable check. The Plant Superintendent acknowledged the inspector's comments.

The second MR concerned #12 Saltwater Pump, initiated on July 15, 1983. The inspector was concerned regarding the apparent length of time required to investigate a packing leak on a Saltwater pump so he examined the circumstances surrounding the delay.

The MR was still active on the MR tracking system, however the Maintenance Planner did not have the work planned or scheduled so he thought that the job was complete or being administratively reviewed by Quality Control (QC). The planner indicated that it was not standard practice to adjust packing under MR's. A monthly Preventive Maintenance (PM) Item (1-12-M-W-1) was already in place and such work would normally be documented as completed under the PM.

The inspector then checked QC records and found that the PM had been worked on December 8, 1983. Because an MR was involved QC witnessed this PM. The QC inspector noted in his report "witnessed mechanic check leak off on pump." Leak off was fine. This was another classic case of an operator not knowing about mechanical equipment and writing a useless MR.... *NOTE: Gland is bottomed out, planners notified." The MR was not closed out however, because the Unit 1 foreman had held up the MR in order to initiate a new MR to replace the packing. (The new MR was not written as of January 30, 1984.)

The inspector checked the historical records for the monthly PM for #12 Saltwater Pump packing adjustment. Since the MR was initiated on July 15, 1983 the PM had been performed 4 times prior to the inspection on December 8, 1983. The packing required adjustment the first time the PM had been performed on July 25, 1983 and the mechanic had noted at the time that no further adjustment of the gland was left.

Notwithstanding this information regarding the condition of the packing no action was initiated to replace the packing.

The inspector discussed the comments of the QC Inspector with the General Supervisor-Operations Quality Assurance (GS-OQA). The inspector noted that a more thorough examination of the conditions by the QC Inspector would have revealed the fact that the packing had been examined many times since the deficient condition had been identified. The packing leakage had been corrected within 10 days of identification (apparently correctly by an operator). The deficiencies regarding working of this MR centered more around delays in scheduling and a failure to follow though administratively on problems identified during the conduct of the work. As a result, a MR to replace the #12 Saltwater Pump packing had not been written as of January 30, 1984, when the need had been identified on July 25, 1983. The GS-OQA stated he would review the circumstances surrounding this MR with the QC Inspectors.

The inspector also examined the MR paperwork to determine why the Deficiency tag was still in place on the equipment if the MR had been completed. The "Work Area Clean and Deficiency Tag Removed" block had been initialed by the lead man, however the tag had not been removed. The inspector noted that removal of deficiencies appeared to be a generic weakness in the licensee's corrective maintenance programs and recommended that the licensee develop a method to verify accuracy of such tags. This item is unresolved (317/84-01-04).

On January 12, 1984 the inspector noted that the Control Room copy of the computerized MR tracking system was several weeks old and apparently was not being updated. Discussions with Maintenance Personnel revealed that the contract clerk who entered [illegible] into the system had not returned to work following a vacation break [illegible] the system was not being updated. The licensee was in the process of initiating a new, on line computerized MR tracking system. The Plant Superintendent stated that the old MR tracking system would be updated and used in parallel with the new system during system startup. On January 20, 1984 the inspectors attended a training session on the licensee's new Maintenance Request Tracking System scheduled for implementation during the January to March 1984 time frame. This new system will contain more information than the previous system, will be real time (each department updates system directly thereby reducing data processing delays), and will provide additional sorting and management monitoring capability. This improved system will serve as an interim until implementation of a broader management system (MIS) in about a year.

On January 19, 1984 the inspector attended a licensee Maintenance Planning meeting to schedule maintenance for the following day. The licensee recently instituted a quarterly Planned Maintenance (PM) eddy current check of tubes in the Component Cooling (CCW)/Saltwater(SW) and Service Water(SRW)/Saltwater heat exchangers. Eddy current testing had been done periodically since 1978 and had pointed out pitting corrosion problems of the saltwater side of the tubes. Eddy current checks under the new PM were done on the Unit 1 SRW heat exchanger #12 on January 18, 1984. Test data indicated that approximately 8 tubes should be plugged to give a total number of 49 plugged tubes in the heat exchanger. It also indicated some degree of pitting in all tubes tested.

The inspector spoke with the licensee's engineer assigned to monitor degradation in the CCW and SRW heat exchangers. That individual was instrumental in initiating the eddy current PM and has been (for retubing maintenance planning purposes) trending tube failures. The engineer recently determined that additional calculations needed to be performed to determine the maximum number of tubes that can be plugged and still meet heat transfer design requirements. Since the maximum percentage of tubes plugged in any of the eight heat exchangers involved (4 heat exchangers per unit) is 2%, some margin should exist but that margin presently is not well quantified. The inspector confirmed that the engineer knew how many tubes were plugged in each heat exchanger.

Unit	Heat Exchanger	# of Tubes Plugged
1	#12 SRW	49
1	#11 SRW	22
1	#12 CCW	3
1	#11 CCW	None
2	#21 CCW	19
2	#22 CCW	9
2	#21 SRW	7
2	#22 SRW	5

The inspector was concerned that the Inservice Inspection program (ASME Code Section XI 1974 edition through Summer 1975 Addenda) does not require eddy current testing for this equipment and that perhaps this type of testing should be required at this plant and generically in other licensee inservice testing programs. This question will be reviewed by NRC Region I staff personnel. The inspector asked to be kept informed of the results of the margin calculations. This item will be followed (317/84-01-06).

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 test was reviewed:

--0-73-1, ESFAS Equipment Performance Test (#12 LPSI Pump) observed on January 20, 1984.

9. IE Bulletin Followup

The inspector reviewed licensee actions on the following IE Bulletin(s) 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.

--(Closed) I&E Bulletin 81-03 (317/81-BU-03) Flow Blockage of Cooling Water Safety Components by Corbicula sp. and Mytilus sp. The licensee submitted their original reponse to this bulletin on May 7, 1981. A second submittal was made on January 27, 1983 in response to futher NRC questions.

The licensee stated that neither species is present in the vicinity of the plant. Further, the licensee stated that controls have been established for prevention of bio-fouling and described those controls.

10. Operator Requalification Progrm

During the week of January 9, 1984, the inspector reviewed the requalification program for licensed operators and the implementation of that program. Specific items reviewed included:

(1) Program description to verify compliance with NRC requirements;

(2) Extent of program participation by license holders not regularly assigned to operating shifts;

(3) Licensee review of annual exams for weak areas and inclusion of information on these areas in next requalification cycle;

(4) Examination of required reading programs;

(5) Review to ensure information on plant modifications, technical specification changes, and procedure changes was being provided to licensed personnel;

(6) Review to ensure information regarding onsite events was being provided to licensed operators;

(7) Review to ensure pertinent information regarding events at other plants was being provided to licensed operators;

(8) Confirmation that candidates for licensee renewal had completed the requalification program;

(9) Confirmation that proper operator evaluations were being conducted; and

(10) Confirmation that the licensee's program was being audited by the licensee's organization and/or outside organizations.

In general the requalification program appeared to be adequate in scope and effectively implemented. In the recent past, prior to the inspectors review, the program had been reviewed by the licensee's QA group, the Offsite Safety Review Committee (OSSRC), and INPO. Another audit by INPO was scheduled for late January 1984.

The inspector noted to the Operations Training Supervisor that 10CFR55.31(e) requires that, in the event a licensed individual has not been actively performing the functions of an operator or senior operator for a period of four months or longer, he shall demonstrate to the Commission that his knowledge and understanding of facility operation and administration are satisfactory. The licensee's requalification program, as documented in Calvert Cliffs Instruction (CCI) 604E dated August 3, 1983, (Section G.2) indicates that such an individual would only have to demonstrate such knowledge to the General Supervisor, Operations. The Operations Training Supervisor acknowledged that he was not fully aware of the requirements of 10CFR55.31(e). The supervisor further pointed out that the original requalification program submittal (dated February 25, 1975) had been approved by the Commission on March 21, 1975, without the requirement for "demonstration to the Commission". The supervisor stated, however, that CCI 604 would be appropriately changed to incorporate 10CFR55.31(e) requirements. The supervisor stated that currently no licensed individual was in the "inactive" category nor could he recollect any licensed individual ever falling in that category. This item is unresolved pending licensee incorporation of 10CFR55.31(e) requirements into the requalification program (317/84-01-02).

11. Saltwater System

The Saltwater System was inspected to determine system operability and general physical condition. This inspection was conducted by: (1) performing a walk-down of the Saltwater System to determine correct valve lineup, condition of equipment and supports, and general housekeeping, (2) reviewing documentation including system P&ID's and operating instructions, (3) reviewing conformance to Technical Specifications, and (4) reviewing action on maintenance requests. The Saltwater System is important to safety in that it represents the ultimate heat sink following the design basis accident. The system takes water directly from the Bay and circulates it through the Component Cooling and Service Water Heat Exchangers. Discharge is returned to the Bay via the normal discharge or the emergency overboard discharge.

a. System Walk-Down

The system walk-down was accomplished on January 11 and 12, 1984, in the presence of a BG&E representative. The first area viewed was the Intake Structure. This area was noted to be in a particularly untidy condition. Although maintenance was underway, the number of tools, trash, and other material seemed inappropriate. On the Unit 1 side of the Intake Structure, Saltwater Pumps #11 and #12 were operating although #11 showed excessive leakoff. A maintenance request tag was in place stating excessive packing leakage existed. This item is further addressed in the Maintenance paragraph (detail 7). Saltwater Pump #13 was not in operation. On the Unit 2 side Saltwater Pumps #22 and #23 were in operation while #21 was disassembled. Other areas of plant where the Saltwater System is located were reviewed. These included the Service Water and Component Cooling Rooms and the ECCS Pump Rooms. The areas appeared to be clean and the equipment in good condition. It was noted that a number of instrument root valves appeared to be inoperable due to corrosion and a number of equipment labels were missing. These items were referred to the licensee's representative for corrective action.

A check of valve alignment was made by comparing valve positions with those given in Operating Instruction (OI)-29, Revision 7 approved December 2, 1981 for Unit 2 and Revision 10 approved August 17, 1983 for Unit 1. Piping and Instrumentation Diagram, OM-49, Revision 1 dated October 17, 1983, was also used for reference. The valve lineup was as required in the above references except as follows: (1) 1-SW-5208-PP was removed, (2) 2-SW-5209 appeared to have its internals removed, and (3) valves 2-SW-101, 102, and 104 are listed as "locked open" but were found to be closed due to the Saltwater Pump #21 being disassembled. The status of 2-SW-104 was verified in the "Locked Valve Deviation Log" in the Control Room. Valves 1-SW-114 and 115 were also found unlocked and properly controlled by a locked valve deviation entry. Slide gate 2-SW-106 was unlocked but not controlled by a locked valve deviation sheet. It was not clear why this valve (gate) should not be controlled via the locked valve log. The General Supervisor-Operations stated that the slide gates would be added to the list of valves (major flow path valves) requiring independent verification and thus control via the locked valve deviation system. This item, including examination of root valves discussed in the previous paragraph, will be followed (318/84-01-03).

A number of valves, mostly non-safety related air cooler valves in the Intake Structure were not checked due to inaccessibility.

Control Room system indicators on control panels 1C13, 2C13, and 2C24A were checked for proper operation. It was found that motor amperage and header pressure were in appropriate ranges for the operating pumps and valve indications were consistent with observations in the plant. The system mimic on Control Room Panel 2C24A had been corrected using a pen and appeared to be somewhat sloppy.

b. Review of Documentation

The major document for operation of the Saltwater System is OI-29 (Revision 10 for Unit 1 and Revision 7 for Unit 2). These documents were reviewed for adequacy with the following results for Unit 1: (1) The Unit 1 and 2 documents are needlessly dissimilar considering the similarity of the systems, (2) the word "open" is missing on step XIII.2.a,(3) two valves are numbered the same; valve 1-SW-1096 appears on P10 and P26 of the valve lineup, (4) the test of the Saltwater System air compressors in Section IX is meaningless in that no limits on normal process variables are stated. These compressors were inspected and found to have instrumentation for "Intercooler Pressure" and "Distance Pressure Piece". These indications may be helpful in developing acceptance criteria for determining operability of the compressors. For Unit 2, the review of OI-29 revealed that: (1) the procedure does not reflect the role of the water treatment group (it is understood that operators do not adjust water chemistry), (2) no process variables are listed for normal system operation, (3) no procedure is given for normal (system full) startup or operation, and (4) no procedure for monthly test of the air compressors is given. Finally, the Unit 2 valve lineup contained far less detail than the Unit 1 procedure. The inspector concluded that the Unit 2 procedure should be rewritten in a manner which closely resembles the Unit 1 procedure. These problems were discussed with the licensee. The GS-O stated that the procedures would be appropriately revised (318/84-01-01).

(c) Technical Specifications

Two surveillance requirements for the Saltwater System appear in the Unit 1 and Unit 2 Technical Specifications (TS) as follows:

"4.7.5.1 At least two salt water loops shall be demonstrated OPERABLE:

a. At least once per 31 days by verifying that each valve (manual, power operated or automatic) servicing safety related equipment that is not locked, sealed, or otherwise secured in position, is in its correct position.

b. At least once per 18 months during shutdown, by verifying that each automatic valve servicing safety related equipment actuates to its correct position on a Safety Injection Actuation test signal."

The requirements of TS 4.7.5.1a are satisfied by monthly performance of Surveillance Test Procedure (STP) 0-93-1 (Unit 1, Revision 4, dated December 7, 1983) and STP 0-93-2 (Unit 2, Revision 6, dated December 17, 1983). The results of these surveillance procedures were reviewed for 1983. It was found that these tests were performed monthly except for STP 0-93-1 which was not performed during October 1983 which is acceptable since Unit 1 was shutdown (the Saltwater System is not required to be operable during reactor shutdown). The requirements of TS 4.7.5.1b are satisfied along with the Emergency Safety Features (ESF) Logic test which is performed monthly. The STP references for this test are 0-7-1 (Unit 1, Revision 23, dated December 21, 1983) and 0-7-2 (Unit 2, Revision 19, dated September 21, 1983). A review of test results from STP 0-7-1 and 0-7-2 for 1983 indicates that these tests were run on a monthly basis except STP 0-7-1 which was not performed during October 1983.

12. 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:

--December, 1983 Operations Status Reports for Calvert Cliffs No. 1 Unit and Calvert Cliffs No. 2 Unit, dated January 13, 1984.

--10CFR50.59 Report of Changes, Tests and Experiments, dated January 3, 1984.

13. Unresolved Items

Unresolved items require more information to determine their acceptability and are discussed in Details 3.b,c, 6 and 10.

14. Exit Interview

Meetings were periodically held with senior facility management to discuss the inspection scope and findings. A summary of findings was presented to the licensee at the end of the inspection. No written material has been provided to the licensee during the preparation of this report.