U. S. NUCLEAR REGULATORY COMMISSION
Region I

Docket/Report: 50-317/85-09 License: DPR-53
50-318/85-09 DPR-69

Licensee: Baltimore Gas and Electric Company

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

Inspection At: Lusby, Maryland

Dates: April 1 - May 6, 1985

Inspectors: for J. Foley, Senior Resident Inspector — 6/12/85 date

for D. C. Trimble, Resident Inspector — 6/12/85 date

Approved: T. C. Elsasser, Chief, Reactor Projects Section 3C — 6/12/85 date

Summary: Dates of Inspection: April 1 - May 6, 1985 (Report 50-317/85-09, 50-318/85-09)

Areas Inspected: Routine resident inspection 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, and reports to the NRC. Inspection hours totalled 259 hours.

Results: The primary emphasis of this inspection was the Unit 1 refueling outage. That outage has been very well planned and coordinated.

One violation was identified by the NRC where the volume adjustment for audible count rate of Source Range Neutron Flux in the Control Room was reduced to a point where it could not be easily heard. This violation together with (1) licensee identified violation involving an inadvertent Steam Generator Isolation Signal actuation due to operator error (Section 4.d) and (2) some evidence of operator knowledge deficiencies relative to Mode 6 operation (Section 4.a) indicate a possible training program weakness.

Problems were experienced with Main Steam Safety Valve setpoint drift. This is a recurring problem (Section 4.d).

The licensee is assessing the need for possible procedural changes to ensure adequate net positive suction head is available to High Pressure Safety Injection Pumps during all phases of an accident. Licensee emphasis on this effort should be continued (Section 4.d).

Operator response to a plant trip resulting from the failure of shaft seals on a Reactor Coolant Pump was timely and appropriate.

DETAILS

1. Persons Contacted

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

2. Summary of Facility Activities

At the beginning of the period both units were operating at full power. On April 5, 1985, Unit 1 commenced a scheduled shutdown for the cycle 7 refueling. While in Mode 3 on April 6, Steam Generator Main Steam Safety Valve testing took place. Seven (7) of the sixteen (16) valves were found outside the acceptable band. All seven apparently drifted (conservatively) low. During the above testing the unit continued to cool down. Operators inadvertently allowed a steam generator isolation (signal) to actuate causing a temporary termination of the cooldown and isolation of the steam generator. This was caused by a failure of the operator to actuate the SGIS Block signal after "SGIS Block Permitted" annunciator was received. The signal was eventually blocked and cool down continued. At 8:30 p.m. in Mode 4, while conducting safety injection tank isolation valve testing, an inadvertent safety injection actuation took place as a result of a temporary change made to the above test procedure which was not properly detailed. Due to plant conditions, an actual injection of borated water did not occur. Engineering Safety Features (ESF) were reset and cool down and drain down to the Reactor Vessel nozzles was completed without further incident.

Daily outage meetings and maintenance meetings exemplified consistently good communication, planning, assignment of priorities and control of activities. Few delays in the refueling schedule have been incurred. On April 25, reactor operators manually tripped Unit 2 from 100% power due to indication that two of the Reactor Coolant Pump (RCP) shaft seals had failed (controlled bleed off excess flow check valve automatically shut). The Reactor Coolant Pump was secured to prevent further seal degradation and the plant cooled down to commence an unscheduled outage to replace the degraded seal package.

Unit 2 restarted on May 5. Power ascent stopped at 55% power when, due to a faulty protective relay, the closing of a RCP breaker cabinet door caused the tripping of #21A Reactor Coolant Pump and a reactor trip on low reactor coolant flow. On May 7, 1985, Unit 2 recommenced full power operation.

At the end of the period, activities from the refueling outage were still progressing in an orderly manner. Housekeeping throughout the facility remains good.

This report details inspector concerns regarding recently qualified reactor operator knowledge of plant conditions and control room operator training with respect to technical specifications. It is viewed that these contributed to the violation identified herein.

3. Licensee Action on Previous Inspection Findings

(Closed) Violation 317/84-18-01. Failure to Perform a Review of a Change Made to the Facility Operation Which was Described in the FSAR. The licensee revised their Calvert Cliffs Instruction 117 "Temporary Mechanical Device, Electrical Jumper and Lifted Wire Control". The change constituted a major revision which now requires the licensee to perform reviews of temporary changes to the facility prior to installation and requires a written evaluation prior to implementing the change if the change involves safety related equipment or radioactivity. This matter is closed.

(Closed) Unresolved Item 317/80-02-01. Timeliness of Corrective Actions for Faulty Indicators in Systems Containing Radioactive Materials. (Delay in repair of a remote position indicator for a Deborating Ion Exchanger Outlet Valve.) The inspectors have noted no further problems in this area and consider the subject item to have been an isolated event. This item is closed.

(Closed) Unresolved Item 317/84-19-04. The inspector reviewed the Licensee Event Report associated with the (technical) loss of all Emergency Core Cooling systems. The licensee has implemented procedural changes to prevent this event from recurring. Subsequently, the inspectors documented this event as a possible generic concern and forwarded it to Region I for further processing. This item is closed.

(Closed) Unresolved Item 317/84-01-01. The licensee performed a HPSI flow balance test with the throttle valves full open to ascertain that the HPSI pumps would not "run out". This phenomenon was confirmed to not occur at maximum flow. The licensee has also requested a Technical Specification change to delete the upper limit on HPSI pump flow, lower the total required HPSI flow, and specify a minimum flow from the three lowest legs. This resolves this issue. This item is closed.

(Closed) Bulletin 83-BU-04. The inspectors ascertained that the licensee is installing new mobile 28 grease and new front frame assemblies on each Reactor Trip Breaker for both Units 1 and 2. The licensee is also testing the breaker "in place" and has lowered the acceptance criteria to 100 milliseconds. Since the above is being implemented, the licensee is no longer bound by their commitment to the NRC to test all eight RTB's prior to all reactor restarts. This item is closed.

(Closed) Unresolved Item 317/81-08-03. Installation of Sight Glasses in Yard Oil Interceptors. Environmental Technical Specifications regarding non-radiological water quality requirements were deleted in Technical Specification Amendments No. 70 (Unit 1) and 53 (Unit 2) dated May 22, 1982 and the NRC no longer has cognizance in this area. These aquatic requirements are now under the jurisdiction of the U.S. Environmental Protection Agency through the NPDES (National Pollutant Discharge Elimination System) permit system.

4. 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.

(1) Containment Emergency Sump

During a routine inspector walk through of the Unit 1 Containment Building, the inspector noted that the manway into the Emergency Sump, although physically located where it would be difficult for trash and debris to enter (on the side of the sump near the shield wall), is not covered by a protective grate. The inspector asked the licensee to evaluate whether this opening should be protected to prevent debris from entering the sump. Licensee evaluation of the need for a protective grating will be followed by the NRC (IFI 317/85-09-01).

(2) Control Room Environment

During the period control room operators carried out routine activities and responded to two Unit 2 plant trips in a professional, disciplined manner. Unnecessary personnel did not enter the Control Room during the plant transients. To encourage operator professionalism, the licensee has a standing policy for operators in the Control Room to be in uniforms. The inspectors noted several instances during the period where an operator was not wearing the prescribed uniform indicating that licensee management is having difficulty fully implementing this policy. The licensee is making significant improvements to the control boards in the Control Room. Selected boards have been cleaned and painted. Mimic displays and instrument/control switch labels are being replaced and improved. These "human engineering" modifications should significantly aid operations personnel in the performance of their duties.

(3) Discussion with Operators

(a) During routine tours of the control room, the inspector frequently held discussions with reactor operators stationed at the control boards. These discussions related to plant conditions, work activities associated with the reactor plant, primary plant parameters, and status of safeguards equipment. During one such discussion, reactor operators were requested to trace out the flow path of the primary coolant through the shutdown cooling heat exchangers and into the reactor vessel.

The inspector noted that two recently qualified operators, working together, appeared to have difficulty in tracing the flow path via the mimic flow path on the control boards through the shutdown cooling heat exchanger and into the reactor coolant system. The inspector acknowledged that the mimic flow path provided on the control boards is somewhat confusing; however, the reactor operators should unequivocally have instantaneous knowledge of this fundamental flow path. Discussions held immediately thereafter with the senior control room operator ascertained the correct flow path through the shutdown cooling heat exchanger. Subsequently, the inspector interviewed several other operators on various shifts regarding various flow paths and plant conditions and had no questions with respect to their knowledge. The inspector discussed these findings with the General Supervisor, Operations.

(b) On subsequent occasions, the inspector entered the control room and observed that a trend recorder indicated that the reactor coolant temperature had increased from approximately 110 degrees F to approximately 145 degrees F. The inspector discussed this with the reactor operators who indicated that during a HPSI flow test, and the simultaneous removal of the reactor vessel head, the temperature recorder, for no apparent reason spiked from 110 to 145 degrees and had remained there since. The temperature recorder indicated the temperature for the RCS inlet to the shutdown cooling heat exchanger and the RCS outlet temperature from the shutdown cooling heat exchanger to the reactor vessel. The only parameter that had changed was the inlet temperature. The reactor operators assured the inspector that the inlet temperature to the shutdown cooling heat exchanger remained at approximately 110 degrees. This was based upon an RCS wide range temperature indicator located in the cold leg of the steam generator inlet piping. However, because of the nozzle dam installation, this was in a location where a no flow condition existed and therefore was an inaccurate indication. In addition, use of the RCS wide range temperature indication was based on: (1) obtaining the differential temperature across the shutdown cooler and adding that to the shutdown cooling outlet temperature to derive the heat exchanger inlet temperature (RCS inlet temperature), and (2) the fact that the operators knew of no other evolutions that could increase the RCS temperature. The inspector agreed with the operators that the RCS temperature was 110 degrees based upon adding the shutdown cooling differential temperatures to the RCS outlet temperature; however, the inspector told the senior control room operator that the maintenance request already established for the inoperable recorder should have a high priority and should should be fixed within a very short time frame. The senior control room operator agreed and stated that they would have I&C look into it immediately. Further discus-

sions with the control room operators about the temperature recorder's erroneous reading of 140 degrees took place. The inspector questioned the operators in regard to 140 degrees because it was apparent that the operators were still utilizing this recorder to ascertain whether they had sufficient cooling for the RCS. Operators were confident that they were not at 140 degrees; however, they were still using the recorder to determine temperature and temperature changes. The inspector questioned the operators (who were recently qualified) concerning the significance of 140 degrees. The operators could not think of any significance associated with the 140 degrees as indicated on the temperature recorder. The inspector further questioned the senior control room operator in regard to the significance of 140 degrees and it was immediately determined that 140 degrees differentiates Mode 5 from Mode 6. Therefore, if the operators exceeded 140 degrees they would be in effect changing modes from Mode 6 to Mode 5 with the reactor head removed which would potentially violate limiting conditions for operation 3.0.4. The shift supervisor noted this and immediately sent an operator to record a local indication of RCS temperature on the shutdown cooling heat exchanger, thus providing accurate RCS inlet temperatures. The inspector discussed these findings with the GSO. Most significantly the inspector discussed the operators lack of awareness of the Technical Specification requirement requiring mode changes. The GSO stated that operators would be required to review applicable Technical Specifications and review the general operating procedures which they will be required to perform. Further the GSO stated that all plant operators would be required to receive training on the plant modifications made during the refueling outage prior to start up and that literature is currently being distributed to the plant operators regarding the ongoing modifications currently being installed.

The inspector interviewed several other operators on each of the varying shifts and had no further problems with the operators knowledge of the plant status or conditions associated with the refueling. The inspector has in the past and will continue to monitor the operating staff's awareness of operating conditions and plant activity. The inspector observed in the shift night orders directions to plant operators requiring them to review Technical Specifications for the mode they were currently in and to review procedures for upcoming evolutions. On several occasions, the inspector discussed his concerns with the GSO relative to a potential control room operator training weakness, particularly as it pertains to those newly qualified.

(4) Upper Guide Structure Removal

On April 18, at approximately midnight, preparations were being made to remove the upper guide structure from the reactor vessel and place it in the refuel pool cavity. While the Maintenance Department Supervisor and the Refueling Coordinator were in the Containment ready to supervise movement of the upper guide structure, the refueling shift supervisor left the Containment and went to the control room in order to brief the control room on specific information regarding the removal of the upper guide structure. Concurrently, the Maintenance Supervisor and Refueling Coordinator had the upper guide structure removed from the reactor vessel and placed in the refuel pool cavity. Removing the upper guide structure from the reactor vessel constitutes a core alteration. Technical Specifications 6.2.2, Facility Staff, requires that all core alterations after the initial fuel load shall be directly supervised by either a licensed senior reactor operator or a senior rector operator limited to fuel handling who has no other concurrent responsibility during this operation. Since the refueling shift supervisor was not present during upper guide removal, this requirement was not met. The inspector was informed of the above on April 18 by the General Supervisor, Operations who stated that the Maintenance Supervisor in the Containment thought that the Reactor Operator standing on the refueling bridge was the shift supervisor directing the evolution. The refueling coordinator saw another individual standing on the side of the refueling pool observing with binoculars the upper guide structure and thought that he was the required licensed operator for core alterations and therefore the maintenance supervisor and the refueling coordinator had the upper guide structure lifted and set in the refuel pool cavity. The GSO stated that the corrective action would be to revise the upper guide structure procedure to insert a required signature for the refueling supervisor to sign off prior to the removal of the upper guide structure. This would ensure the presence of the fuel handling supervisor. The inspector noted that fuel handling supervisor sign offs are required in the head lift procedure and in the refueling shuffle procedure. The removal of the upper guide structure procedure is primarily controlled by maintenance personnel. Notwithstanding a lack of sign off by the refueling supervisor, the maintenance personnel were aware that a refueling supervisor must be present during core alterations. This is considered a licensee identified violation and meets the criteria of the NRC policy for not issuing a violation. The inspector had no further questions regarding this matter.

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.

--Diesel Fuel Oil checked on April 3, 1985.
--Unit 2 Service Water checked on April 3, 1985.
--Unit 2 Saltwater System checked on April 26, 1985.
--Unit 1 High Pressure Safety Injection checked on April 11, 1985.
--Unit 1 Containment Spray checked on April 11, 1985.
--Unit 2 Auxiliary Feedwater System checked on April 4, 1985.

No violations were identified.

c. Biweekly and Other Inspections

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

-- During a routine morning tour of the Control Room, the inspector discussed the controls associated with the in progress fuel movement. Fuel management personnel directly involved with the refueling responded more than adequately to the inspector questions and appeared to be thoroughly knowledgeable of refueling activities. However, during a pause in conversation the inspector noticed a momentary quiet condition in the Control Room. The inspector questioned the Senior Control Room Operator (SCRO) regarding the silence and lack of audible source range counts. The SCRO immediately proceeded to check the volume on the Source Range Nuclear Flux Monitor. The inspector, with his ear approximately one inch from the monitor, could just detect that the instrument was functioning. The SCRO immediately increased the volume. The intent of the audible output of the instrument is to be able to detect changes in the reactivity of the core during core alterations.

Technical Specification 3/4 9.3.9.2 requires that "As a minimum, two source range neutron flux monitors shall be operating, each with continuous visual indication in the control room and one with audible indication in the containment and control room."

Contrary to the above, a neutron flux monitor was not audible in the Control Room. This is a violation (50/317/85-09-02).

The inspector subsequently checked the loudness of the Containment indication and found it acceptably loud.

This was discussed with the licensee's representative who stated that an hourly check would be added to the reactor operators logs to verify the operation/audibility of the neutron flux monitor. The licensee also noted that fuel management personnel were in the Control Room calculating the change in reactivity utilizing 1/M plots during the time that the neutron flux monitor could not be heard.

The inspectors subsequently toured the Control Room on numerous occasions and found the flux monitor audible and noted that the appropriate logs have been updated to check the monitor on a shift basis. Based on the above corrective action, a response to this violation is not required.

The inspector identified no other significant concerns.

d. Other Checks

Main Steam Safety Valve Testing

During the Unit 1 shutdown on April 5, 1985, main steam safety valve testing took place in accordance with STP-M-3-1 "Main Steam Safety Valves". The licensee tested 16 main steam safety valves, eight on steam generator No. 11 and eight on steam generator No. 12. Three safety valves on S/G 11 were found out of specification, the largest deviation being 16 pounds from the set point. Four safety valves on steam generator No. 12 were found out of specification low, the greatest deviation being 24 pounds low. The resident inspector reviewed this data with the licensee and ascertained that these valves would be inspected, refurbished, and reset at the required set pressures at the end of the refueling outage. The licensee also stated that a Licensee Event Report would be submitted as a result of the as found data. Through discussions with the licensee, the inspector determined that this type of set point drift is typically found during main steam safety valve testing. The licensee, as part of their corrective action, plans to submit an amendment to the NRC requesting a change to the Technical Specifications regarding the tolerance associated with the set pressure of the relief valves. The current set pressure tolerance allows for a one percent set point drift. The licensee feels that this tolerance is extremely narrow and is causing an excessive amount of LERs to be submitted to the NRC.

The inspector reviewed the above data and ascertained that all valves failed in the conservative direction. The inspector witnessed the rebuilding of many of these valves and independently inspected the internals of several main steam safety valves. The resident inspectors plan to observe the setting of the main steam safety valve set points during start up testing.

The licensee reported these findings to the NRC Headquarters Duty Officer and to the NRC resident inspector on April 6, 1985.

Component Cooling Water

At 3:15 p.m. on April 25, 1985, Unit 1 shutdown cooling was functionally lost when Component Cooling Water (CCW) flow was inadvertently secured to the in service (No. 12) shutdown cooling heat exchanger. The No. 11 CCW subsystem was being tagged out of service when, due to a valve labeling problem, the suction valve to the operating CCW pump (No. 13) from the No. 12 CCW subsystem was shut by the person performing the tagout.

Since the No. 11 subsystem was already partially tagged out, the water supply to the No. 13 pump was interrupted. The problem was promptly noticed by operations personnel and CCW flow to the #12 shutdown cooling heat exchanger was restored by 3:23 p.m. Later investigation showed that the labels for valves 1-CC-121 (No. 13 pump suction from No. 12 CCW header) and 1-CC-122 (No. 13 pump suction from No. 11 header) were interchanged, and the label problem was then corrected. A walk down of both CCW suction headers was conducted to confirm that no additional labeling problems existed. In general, valve labeling in the plant is very good and this appears to be an isolated problem.

Verification of Technical Specification

At various times during the refueling outage, the inspectors ascertained that applicable Technical Specifications (TS) were being adhered to. This was done on a random basis until all TS for Mode 6 were reviewed. The results of this review are as follows:

TS 3.9.4....requires a minimum of one door in each air lock be closed. the inspector noted that both doors of the Emergency Personnel Air Lock were open; however, in place of the outer door was a fabricated metal plate held in place with clamps and a rubber sealant glued to the outside edge as a seal. Through the plate were wires for steam generator eddy current testing, an air hose, and a fire hose, providing Containment with fire protection from yard hydrant No. 8. Each of the above passed through a penetration in the plate and were sealed with "EB" green tape. Additionally, two other penetrations in the plate were sealed with tape.

TS Bases requires that the penetration be sealed to restrict the flow of contaminated air in the event of a fuel handling accident, acknowledging the absence of a pressure build up.

Discussions with the licensee indicated that a test was performed on the structure to restrict the passage of air, that it met the intent of Technical Specifications and that it is checked periodically by shift personnel. The inspector agreed that the structure was a significant mass that should meet the intent of the TS requirement; however, it did not meet the wording of the specification. The licensee stated that they would submit a TS change to formalize the evolution.

The inspector stated that a formal test with definitive acceptance criteria should be performed, and that the licensee should request that provisions be included for installing such a device, in Technical Specifications.

The inspector also discussed this with the NRC License Project Manager who agreed that a TS change should be submitted. The licensee's representative provided the inspector with a memorandum with copies to the licensee's site managers, which states that the above items have been agreed to, assigns responsible individuals to complete the above action

items and infers a completion date of prior to the next refueling outage. This matter is unresolved pending a change to Technical Specifications (317/85-09-03).

SGIS Actuation; Licensee Identified Violation

On April 6, 1985, during the performance of OP-5 "Plant Shutdown from Hot Standby to Cold Shutdown" a 95 degree F per hour cool down rate was established. As temperature and pressure decreased, operators failed to block the expected Steam Generator Isolation Signal (SGIS) at 720 psia and a SGIS occurred as designed, interrupting the cool down.

The procedure OP-5 specifically requires, in IIA. Initial Condition, 10, "SGIS and SIAS block keys inserted in their respective key switches", and in B.3.f(2) "when (SGIS Block Permitted) is received, (SG pressure of approximately 767 psia) Block SGIS Actuation Channels 11 (21) and 12 (22) -Caution- do not reduce steam generator pressure below 720 psia until SGIS is Blocked." The procedure is clearly detailed, without ambiguity. The operator stated that he simply missed the steps and when "Block Permissive" was received, the keys to block the actuation were still in the shift supervisors possession and there was insufficient time to stop the cool down, insert the keys and block the SGIS.

The licensee reported this to the NRC Duty Officer and the resident inspector and a Licensee Event Report (LER 85-05-01) will be issued. The licensee's corrective action will consist of the following:

(1) Revise the plant cool down procedure to make insertion of the keys which block SGIS an action step in the procedure.

(2) Evaluate the repair or replacement of the SGIS block key switches so that the keys are easier to insert.

(3) Verify the trip points of the SGIS and SGIS block sensor channels to ensure the operator has adequate time available to block SGIS without having to interrupt the plant cool down.

(4) Review plant procedures to ensure adequate guidance is given to prepare for blocking of all engineered safety features signals that are required to be blocked during plant cool down. Guidance will be added to the procedures to instruct the operator to stop cool down or depressurization during a plant cool down if an engineered safety features signal cannot be promptly blocked once a block permitted condition is reached.

(5) Make all operators aware of this incident.

This event constitutes a licensee identified violation of Technical Specification 6.8.1 which requires the licensee to implement established procedures. OP-5 steps II A and B.3.f(2) were not implemented as required.

This self identified violation meets the criterion of the NRC enforcement policy for not issuing a notice of violation. The licensee corrective action appears adequate. The inspector had no further concerns.

SI Actuation; Licensee Identified Violation

On April 6, 1985 at 8:32 p.m. during the performance of STP 0-35-1 "Safety Injection Tank Valve Test," an inadvertent safety injection actuation occurred as a result of a temporary change to the procedure which was made to account for the shutdown condition and reduced system pressure but failed to detail step by step the process for insuring the SIAS signal remained blocked during the test.

The normal procedure requires the tripping of the SIAS A and B-10 logic modules and each channel of pressurizer pressure (PP) (ZD, ZE, ZF and ZG), by depressing the associated SIAS test button and rotating a test level adjusting screw (if necessary) until the channel trips. The procedure however did not provide for a condition where the plant pressure was already below the SIAS pressurizer pressure (sensor) set point and, therefore, the logic was already tripped. This therefore required a revision to the procedure which required reducing the sensor set point below the existing pressure system and unblocking each channel in order to permit the test to be performed according to procedure.

A change was made to the procedure and approved by a reactor operator and senior reactor operator which required dialing down the pressurizer pressure set points to zero for channel ZD through ZG and unblocking the associated signal for channels ZD through ZG.

The operator reduced the PP set points for channel ZD, and unblocked ZD then reduced channel ZE, and unblocked ZE. At this point, the SIAS occurred because only two blocks (ZF and ZG) were still set and the logic requires three of four blocks to be set to prevent SIAS actuation. The two of four required trips were in effect (ZF and ZG) since actual plant pressure was below the normal set point. The system logic requires only two channels to trip but requires three channels to block. The change snould have required reducing the set points of all sensor channels first and then unblocking the respective channels.

Borated water was not injected due to system pressure was still above the shut off head pressure of the high pressure safety injection pumps.

The NRC Duty Officer was notified and the resident inspector as well.

The licensee has submitted an Licensee Event Report (LER 85-04-01) regarding the event. Corrective action will include:

(1) Include detailed instructions on how to remove and reestablish block of SIAS in the procedure that was being used at the time of the incident (STP 0-35).

(2) Review all Surveillance Test Procedures to determine if additional guidance is needed to remove or reestablish blocks of SIAS signals or other Engineered Safety Features Signals which have blocks associated with them.

(3) Make all operators aware of this incident.

This event constitutes a licensee identified violation of ANSI 18.7 Section 5.3.2.7 which the licensee committed to as a result of committing to Reg Guide 1.33 as stated in the licensee's Quality Assurance Manual. ANSI 18.7 Section 5.3.2.7 requires procedures to provide the degree of detail necessary to perform the required task. This detail was not provided.

This self identified violation meets the criterion of the NRC enforcement policy for not issuing a Notice of Violation. The licensee's corrective action for this event appears adequate. The inspector had no further concerns.

Steam Line Support

Late on May 1, 1985, the support R-4 on line EB-1-2005 was found to have separated at the wall anchor. This support is located on the 34 ft. level of Containment on Unit 2 No. 22 steam line. This hanger was replaced last refueling outage based on a recommendation by Teledyne that the support be strengthened. Preliminary indication was a fault in the weld of the support to the wall anchor. Action was being taken by the licensee to try and confirm the cause of failure. The licensee planned to fabricate a replacement and strengthen the area of attachment. A walk down of the No. 21 and No. 22 steam lines indicated no other supports were of this particular type and attached to the anchor in the same fashion. As of May 3, 1985, the licensee was still investigating the situation while simultaneously preparing a replacement. The inspector had no further questions at this time because (1) the failed support was designed to be stronger than the original support and the original support had no previous problems, (2) the area of the problem was at a weld, (3) the replacement was to be fabricated and weld area strengthened, and (4) the licensee considered the line inoperable until support was fixed.

Safety Injection Check Valves

Evidence of gasket leakage was found on Unit 2 safety injection check valves, SI-237 and SI-247. Since these valves are exposed to borated water as part of the primary pressure boundary and contained carbon steel

studs, the studs were removed for examination for boric acid corrosion and/or cracking. Boric acid degradation of the fasteners was found and the fasteners were replaced. The licensee's action was in accordance with their response to and the guidance furnished in IE Bulletin No. 82-02, Degradation of Threaded Fasteners in Reactor Coolant Pressure Boundary of PWR plants. A sampling of plant procedures by the inspector reflect continued compliance with IEB 82-02 requirements.

High Pressure Safety Injection (HPSI) Flow Balance Test

Since January of 1984 (see Section 6 of Inspection Report 50-317/84-01, 50/318/84-01), the licensee has experienced problems meeting the very narrow band of flow requirements of Technical Specification (TS) Surveillance Item 4.5.2.H in which a flow test must be conducted (every 18 months or following system modifications altering system flow characteristics) to verify 170 +/- 5 gpm to each injection leg. During a test on April 15, 1985, flow was low through one auxiliary HPSI header (155 gpm) and two main HPSI headers (159 and 152 gpm) on Unit 1. Similar problems were found on Unit 2 on May 2, 1985. The licensee requested TS changes for both units (dated February 22, 1985 for Unit 1 and April 10, 1985 for Unit 2) which would increase the range of acceptable HPSI flow. The revised TS would define a minimum acceptable HPSI flow balance value for the sum of the three lowest leg flows to ensure the flow rate sufficient to preserve peak clad temperature margin in a Small Break LOCA. It would also eliminate the upper limit for HPSI flow. During this inspection period, the licensee conducted a maximum HPSI flow test on Unit 1 which verified that pump run out would not occur and that pump motor horsepower requirements would not be exceeded in a maximum flow condition. The results of those tests were submitted to NRR on April 23, 1985.

A second issue associated with HPSI flow is whether sufficient net positive suction head (NPSH) will be available to the HPSI pumps at all times during an accident. On April 11, 1985, the inspector reviewed NPSH calculations performed by a licensee staff engineer. Those calculations show that as long as the HPSI pumps are drawing water from the Refueling Water Tank (RWT), adequate NPSH exists. However, after a Recirculation Actuation Signal (RAS) is initiated and HPSI pump suction is shifted to the Containment sump, a much smaller margin exists between the NPSH available and the NPSH required. Currently, after the RAS and the minimum required HPSI flow following a large break LOCA is being delivered to the Reactor Cooling System (RCS), only a two foot head margin exists (21.5 ft. available, 19.5 ft. required). If the HPSI leg flow control valves are allowed to remain in a full open position, as would be allowed by the requested TS revisions, little or no NPSH margin would be available. It should be noted that some conservatism exists in the licensee's calculations which would tend to underestimate available NPSH. The inspector, however, was concerned that the NPSH margin was small in a post RAS condition and therefore asked the Plant Superintendent to evaluate whether it is necessary to reduce HPSI flow to a level (just prior to

RAS) that will both guarantee adequate core cooling and yet ensure proper NPSH margin. The Plant Superintendent stated that such an evaluation was already in progress and that a proposed procedural change was being reviewed by the Plant Operations and Safety Review Committee. Additionally, the FSAR describes motor operated valves (MOVs) which can be opened to divert a portion of Containment spray flow (recirculated water which has been passed through "shutdown cooling" heat exchangers and is therefore at a reduced temperature) to the suction of the HPSI pumps to increase the NPSH available. Currently, those MOV's are not powered from a diesel-backed bus. Since this means of improving NPSH exists to ensure its availability, the inspector asked the licensee to evaluate whether the power source for those MOV's should be shifted to a diesel-backed bus.

The inspector learned that the HPSI flow measuring instruments are not included on the Q-list. After discussions with the licensee, a Q-list change was initiated to add these instruments to the Q-list.

Licensee actions to evaluate procedural changes for HPSI flow and evaluate power source for Containment spray diversion valves will be followed by the NRC (IFI 317/85-09-05).

5. Refueling Outage

On April 5, 1985, Unit 1 commenced its cycle 7 refueling outage. Several outage meetings had been previously held. Planning and preparations were consistently well-coordinated. Inspectors attended daily outage information meetings, and periodically, more detailed meetings. Meetings were all succinct, coordinated and appeared effective. With the outage 75% complete, the schedule has been rigidly adhered to with only minor slippage. Interface work among working groups is well-coordinated. The licensee seems to maintain very good control of contractor personnel. Both corporate and site management attend the daily outage meetings and appeared involved in ongoing activities. Decision making was routinely made at a level that assured adequate, management review, Plant Operation Safety Committee reviews, and 10 CFR 50.59 reviews.

With minor exceptions, Quality Assurance controls associated with various refueling activities were well-controlled. However, on one occasion, reactor operators dropped a set of binoculars into the Reactor Vessel from the refueling bridge. These were subsequently retrieved. Overall, QA controls were good.

During the refueling, the licensee plugged 12 tubes in Steam Generator No. 11 and 7 tubes in Steam Generator No. 12 as a result of 65% eddy current testing of the Steam Generators.

Extraction steam line examination has so far resulted in the replacement of 42 sections of pipe/fittings. Examination of No. 11 Saltwater Header revealed no degradation of wall thickness, however, two to three inches of marine growth were affixed to much of the wall inner diameter. The licensee monitors saltwater flows and heat exchanger D/Ps regularly to monitor any effect of this marine growth. The licensee also replaced the Service Water and Component Cooling Heat Exchanger Channel Heads for Unit 1 with rubber lined steel channel heads.

Inspectors witnessed portions of the above activities and more closely monitored, with detailed review of procedures and the controls, the following:

(1) The Rebuilding of the Main Steam Safety Valves;

(2) Refurbishing the No. 12 Main Steam Isolation Valve;

(3) Inservice Inspection/Hydrostatic of selected components;

(4) Installation of the Reactor Cavity Seal and the difficulties associated with Steam Generator Nozzel Dams;

(5) Replacement of No. 12B Reactor Coolant Pump Motor;

(6) Installation of portions of the Reactor Vessel Water Level Monitoring System modification; and

(7) Periodic monitoring of the fuel shuffle both in Containment and in the Spent Fuel Pool. (Operators moved approximately 13 bundles per shift without incident. Delays were incurred due to bridge alignment, cameras and spreader problems.)

During routine tours of the Containment, the inspector noted that ALARA visibility was not well evident. Signs, postings or controls emphasizing ALARA were not readily visible. Exposure planned for the installation of steam generator nozzle dams was approximately 26 man rem. Actual dose received was approximately 40 man rem. However, total dose planned for the outage was 250 man rem and, with the outage nearing the end, dose for Unit 1 outage is currently about 185 man rem. Removal of the nozzle dams required only 3.5 man rem. Total dose received for the previous outage was approximately 270 man rem. Discussions with the licensee indicate that they plan to make ALARA more visible as well as reduce the total rem exposure.

Future outage activities consist of an Integrated Leak Rate test of the Containment, a Reactor Coolant System Hydrostatic test, and Startup testing. Paralleling to the grid is currently scheduled for May 24, 1985.

6. Events Requiring Prompt Notification

The circumstances surrounding the following events requiring prompt NRC notification pursuant to 10 CFR 50.72. were reviewed. For those events resulting in a plant trip, the inspectors reviewed plant parameters, chart recorders,

logs, computer printouts and discussed the event with cognizant licensee personnel to ascertain that the cause of the event had been thoroughly investigated; identified, reviewed, corrected and reported as required.

-- At 9:32 a.m. on April 25, 1985, Unit 2 was manually tripped from 100% power following an indicated failure of two shaft seals on #21A Reactor Coolant Pump (RCP). The pump was then immediately deenergized. The RCP has three seals and a vapor seal (the vapor seal is designed to withstand full system pressure with the pump off). One seal (there is a possibility that the seals themselves did not fail but instead elastomer material may have failed in orificed bypass paths around the seals) had failed previously, and therefore, potentially only the vapor seal remained in tact. The vapor seal prevented any loss of Reactor Coolant. Plant systems functioned normally following the trip with the exception of #21 Atmospheric Dump valve which failed to fully close on demand due to a failed positioner. That valve was manually isolated.

Pressurizer pressure remained above 1880 psig and Tavg above approximately 516 degrees F. The licensee commenced a plant cool down and planned an eight day outage for seal replacement. As of April 29, 1985, the licensee was still investigating the cause of the RCP seals failures.

The investigation of the RCP seal and atmospheric dump valve failures will be followed by the NRC (IFI 317/85-09-04). Operator response to this event was timely, well-coordinated, and correct.

-- At 1:20 p.m. on May 6, 1985, Unit 2 automatically tripped (on low reactor coolant flow) from 55% power when the breaker for #21A Reactor Coolant Pump (RCP) opened due to the action of a "86 device" protective relay. The unit had just returned to power operation (on May 6) after a 10 day outage to replace the seal package for the same RCP. Trouble shooting revealed that an over current protective relay (251) for phase C tripped when an electrician shut the RCP breaker PT compartment door on which the relay was located. Plant systems functioned as designed following the plant trip. The 251 relay was found to be defective. The licensee restarted the unit as soon as the defective relay was replaced.

No unacceptable conditions were identified.

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.

-- MO 205-084-302A, Modification to ARC Valve - Unit 1 Auxiliary Feedwater System.
-- Installation of Unit 1 Reactor Cavity Seal.
-- Service Water and Component Cooling Water Channel Head Replacements.
-- Modifications to Reactor Vessel Head for Reactor Vessel Level Monitoring System.
-- Reactor Coolant Pump Motor Changeout.

No unacceptable conditions were identified.

8. Surveillance Testing

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

-- STP-M-510-1, Unit 1 RPS Calibration check.
-- PM-1-58-I-Q-4, Revision 5, Unit 1 Temperature Loop TH and TC to RPS.
-- STP-M-525-1, Unit 1 Auxiliary Feedwater Actuation System Calibration.
-- STP M 220-1, Unit 1 Functional ESFAS Test.
-- PTP-1-SDC-10Y-1, Shutdown Cooling Heat Exchanger Hydrostatic Test.
-- PTP-1-HPS-10Y-1, Hydrostatic Test of High Pressure Safety Injection Pumps.

No unacceptable conditions were identified.

9. IE Notice 84-86 Isolation Between Signals of the Protection System and Non-Safety Related Equipment

This notice concerned the potential for a failure of a mercury wetted relay in the non-safety related plant computer multiplexer to adversely affect plant protection system sensor outputs by shunting current loop resistors. Through discussions with licensee engineering and Instrument and Control personnel, the inspector found that adequate isolation exists (through optical isolators) between the Reactor Protection (RPS) and Engineered Safety Features Actuation (ESFAS) systems' outputs and the multiplexer. However, the current loops for Channel A pressurizer pressure and reactor coolant flow, in addition to providing input signals for RPS and ESFAS also directly provided "unisolated" input signals to the plant computer. The potential then exists for these channels to be adversely affected by non-safety related equipment failures.

Three redundant sensor channels (B, C, and D) exist which would not be affected by a multiplexer fault. This redundancy should ensure that adverse plant conditions/parameters would be detected and proper automatic protection action taken. During the next refueling outages for each unit (Fall 1985 for Unit 2, Fall 1986 for Unit 1), the licensee plans to install a new plant computer with a data acquisition system which, through the use of isolators, will ensure that no computer equipment failure will affect any sensor output. This will resolve the problem.

10. Radiological Controls

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

No significant concerns were identified by the inspector.

11. Observations 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.