U.S. NUCLEAR REGULATORY COMMISSION
REGION I

Report Nos. 50-317/88-08
50-318/88-09

Docket Nos. 50-317
50-318

License Nos. DPR-53
DPR-69

Licensee: Baltimore Gas and Electric Company
P. O. Box 1475
Baltimore, Maryland 21203

Facility Name: Calvert Cliffs Nuclear Power Plants, Units 1 and 2

Inspection At: Lusby Maryland

Inspection Conducted: April 4-8, 1988

Inspector: P.K. Eapen 5/26/88
for Harold Gregg, Senior Reactor Engineer date

Approved by: P.K. Eapen 5/26/88
Dr. P. K. Eapen, Chief, Special Test Programs Section, EB, DRS date

Inspection Summary: Inspection on April 4-8, 1988 (Combined Inspection Report Nos. 50-317/88-08 and 50-318/88-09)

Areas Inspected: Licensee's implementation of Inservice Testing (IST) of pumps and valves.

Results: No violations were identified. One item was designated as unresolved and pertained to a steam line check valve failure and further licensee review of this type valve is warranted. Two other issues relating to: 1) an Auxiliary Feedwater piping revision; and, 2) the Containment spray pump acceptance criteria, were identified by the licensee and are in process of resolution.

DETAILS

1.0 Persons Contacted

1.1 Baltimore Gas and Electric (BG&E) Company

*R. Allen, Principal Engineer, NESD
*R. Douglass, Manager QASD
*R. Heibel, GSO1, NOD
J. Lemons, Manager, Nuclear Operations Department
*W. Lippold, Manager, NESD
T. Lupold, Systems Engineer
*J. Lohr, A-G-S-O, NOD
*R. Niedzielski, Operations Surveillance Coordinator
*C. Phifer Jr., QA Auditor, QASD
*D. Shaw, Licensing Engineer, NESD
T. Sydnor, Principal Engineer, Secondary Systems
C. Mahon, Principal Engineer, Primary Systems
R. Martin, Reactor Operator
K. Mills, Systems Engineer

1.2 U.S. Nuclear Regulatory Commission

*D. Trimble, Senior Resident Inspector

* Denotes those present at the exit meeting.

2.0 IST Program Background

The inspector reviewed the program background with cognizant licensee personnel. The following determinations were made.

- The IST pump and valve testing program is a separate and distinct program. It is a combined Unit 1 and Unit 2 program.
- The licensee is currently in the second ten year interval. The second ten year interval start date is April 1, 1987 for both Units.
- IST commitments are to ASME Section XI, 1983 Edition through summer 1983 addenda
- The second ten year program is in the final stage of Office of Nuclear Reactor Regulation (NRR) review.
- A meeting between NRR and their consultant and the licensee was held on site on February 17-19, 1988.

- Based on the meeting discussions several additional evaluations and relief requests were to be submitted by the licensee.

- Final program modifications will be made by the licensee upon receipt of NRR response.

3.0 IST Organization

Lead responsibility for writing, reviewing and modifying operational Surveillance Test Procedures (STPs) and initiating program relief requests is with the surveillance coordinator. The coordinator schedules the operational STs, reviews test results and has involvement in resolution or referral of problem areas. The coordinator is in the operations reporting chain. Problems encountered during testing that is performed and reviewed by operations are referred to systems engineers whose reporting chain is the engineering department.

The scheduling of mechanical STPs (those to disassemble valves or to test pressure relief valves) is through the maintenance planning and scheduling unit. The oversight or responsibility for these IST area is with the system engineering whose reporting chain is the engineering department.

The operational surveillance coordinator and the systems engineering were found to be technically competent, knowledgeable and effective in their performance of the operational STP's.

At the start of this inspection licensee management advised the inspector that the IST organizational structure was to undergo a complete reorganization and additioinal personnel will be added. The impending IST primary responsibility will be under the Performance Engineering unit in the Nuclear Engineering Services Department. The effectiveness of the forthcoming IST organizational structure will be reviewed in a future NRC inspection.

4.0 Test Results STP-0-5-2 Auxiliary Feedwater System Pump Tests

The inspector reviewed the quarterly test results of pump 21 AFW performed on March 29, 1988. This test is performed with minimum recirculation line flow. The pump flow was 91. gpm (below the 92.7-96.8 alert range and below the low valve 92.7 action range). The pump was retested on March 31, 1988 after verification of instruments and the flow was 91.5 and still in the action range. Lifting of a recirculation line relief valve (2RV 4501) was suspected as the cause for reduced flow. The pump was declared out of service and required further engineering follow-up.

On April 1, 1988 the pump was again tested and was still below acceptance. A retest was then performed with additional steps taken to isolate relief valve 2RV 4501. This resulted in a flow of 104 gpm and within the acceptance range. This testing verified that the problem was a system and not a pump or valve problem. Running the pump at shutoff head (with only a minimum recirculation) may cause higher pressure fluctuations in the line at the relief valve. The normal AFW flow to the steam generator would be higher and would not cause relief valve lifts, therefore, the test encountered problem is not considered a safety concern. The inspector also determined that the licensee had discussions with NRR and has submitted a relief request to full flow test the AFW pumps during refueling outage.

The licensee recognized that the system may have operating occasions similar to the minimum recirculation pumping conditions and is planning a design revision. The revision would install a flow orifice in the line to the relief valve. Upstream of the relief valve there had also been some evidence of leakage at a cooler which may also indicate the need for the flow orifice in that line. The inspector had no further questions at this time.

4.1 Review of STP-O-5-2 Auxiliary Feedwater System Pump Test

During review of this STP the inspector noted that the licensee's flow acceptance range was 86.8-108.1 gpm. This represents a range of .94 to 1.05 times reference flow which is more than the ASME code acceptance range of .94 to 1.03 times reference flow.

The inspector determined that the licensee's program submittal provided the basis to increase the flow and differential pressure high end of the range. This topic was also discussed with NRR at the February meeting. The licensee's bases were that pumps would not produce more flow over time, small increases in differential pressure are not significant, and instrument inaccuracy and water density changes could readily lead to spurious alert and action ranges.

4.2 Test Results STP-O-73-1 ESF Equipment Performance Test (HPSI, LPSI, CS)

The inspector reviewed the test of number 21 containment spray pump. The recorded differential pressure of 196.5 was below the 196.6 acceptance range and the pump head of 454.9 feet was below the minimum acceptance of 455 feet. A maintenance request was written to evaluate the problem. Instrumentation problems were believed to be the cause; however, upon subsequent testing this was found not to be the case.

The inspector reviewed the STP further and discussed the STP acceptance requirements with the operations surveillance coordinator. The inspector determined that the STP acceptance was an ECCS requirement from the original plant design criteria and is more stringent than IST requirements. The licensee's engineering department is presently evaluating the ECCS criteria. They are attempting to lower the differential pressure acceptance range for the ECCS while still maintaining a more conservative than code required IST range. The inspector had no further questions at this time.

5.0 Test Witnessing STP-O-65-2 Quarterly Valve Operability Verification - While Operating

The inspector witnessed the stroke testing of HPSI flow path MOVs, SI-616, 626, 636, 646, 617, 627, 637, 647, 653, 654, 655 and 656. Requirements for testing these valves is described on pages 8 to 14A of the subject procedure. The inspector observed the stroke timing and recording of data for each of the valves and verified in each case that the stroke alert range was not exceeded.

This test procedure had recently been revised to include IEB 85-03 requirements to obtain starting and run current (amps). The valve testing witnessed by the inspector was performed efficiently and was effectively controlled by the reactor operator.

6.0 Check Valve Failure (Valve 2 MS103)

The inspector observed the disc of a failed check valve that had been on the main steam supply to auxilliary feedwater pump No. 21. The disc was bent approximately 70°, had a several inch fracture crack at the bend area, and a large piece of one hinge boss was completely broken off. The disc seating surface also had significant seating surface wear and the relatively high hinge pin location may have contributed to the top disc edge being caught in the valve seat as the disc was checking closed.

The valve was a 6" tilting disc check valve manufactured by Chapman Division of Crane Company. This valve is an angular split body design with the two body halves bolted together. Since the valve is butt welded in line and the angular body split is through the piping run plane, there is no means to open the valve for inspection other than cutting it out of the line.

Based on the inspectors observations of the broken disc and from review of the valve drawing, the inspector concluded the valve may not be suitable for the service condition. The inspector was also concerned about the other valves of this design installed in each of the plants. The inspector determined that both the MS-103 and MS-106 valves on Unit 2 were replaced with 6"-900# Anchor Darling tilting disc check valves which

have a top access pressure seal cover. The licensee is also planning some action related to other valves of this design in main steam lines farther downstream.

The inspector reviewed STP-O-67-2 which verifies actuation of the valve. The STP however, doesn't verify check closed position and since the valves can't be disassembled and inspected the licensee is evaluating how to verify that the valve is intact and can perform all its operational functions. The inspector determined that this issue was also discussed during the meeting with NRR.

This item is unresolved pending the licensee's determining if the valve design is fit for service, and resolution of actions required on the same location valves on Unit 1 and also other valves of this type on both Units (50-317/88-08-01 and 50-318/88-09-01).

7.0 Main Steam Safety Valve (MSSV) Ring Settings

The inspector reviewed the licensee's activities related to NRC Information Notice (IEN) 86-05 and its supplement. This notice provided licensee's information of potential problems with ring setting adjustments on MSSVs (an IST listed component) which could prevent obtaining full rated flow capacity.

The inspector determined that the licensee has 16 MSSVs on each unit (8 on each steam generator). The valves are Dresser 6" x 10" model 3707 R AX RT 22 valves. The inspector also determined that this licensee has been actively involved with MSSV ring settings and each of their valves are set to the ring settings (lower ring at -8 notches and upper ring at +160 notches) as recommended in the manufactures letter dated October 30, 1984. Additionally, as a result of LER 85-11 concerning MSSVs out of set point range, the licensee had two of their valves (RV 3992 and 3993) tested at Wylie Laboratories (Test Report 48048 of December 23, 1985) under full flow conditions to determine set point, lift and blowdown. Testing was also to determine set points at different ambient temperatures with hydroset and without hydroset (full steam set point).

The licensee currently performs maintenance on 8 valves each refueling outage. Their maintenance procedure RELV-5, Rev. 2 was reviewed. This procedure calls for ring setting determination and verification that as left positions are: lower ring at - 8 notches and upper ring at +160 notches.

Based on the above activities the licensee's Plant Operations Experience assessment committee decided that no further action was required. The inspector concluded that this licensee had performed extensive actions, was knowledgeable of their ring settings, had details of manufacture's recommendations and their valve test report records available, and performs considerable MSSV maintenance with verification of ring settings. The inspector assessed licensee's MSSV ring setting efforts and agreed with the licensee's close out action.

8.0 Unresolved Items

Unresolved items are matters about which more information is required in order to ascertain whether they are acceptable items, violations or deviations. An unresolved item is discussed in paragraph 6.0 of this report.

9.0 Exit Meeting

The inspector met with the licensee's representative at the conclusion of the inspection on April 8, 1988, to summarize the findings of this inspection. Attendees at the exit meeting are listed in paragraph 1.0 of this report.

During this inspection, the inspector did not provide any written material to the licensee. The licensee did not indicate that the inspection involved any proprietary infomation.