UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W.
ATLANTA, GEORGIA 30303

Report Nos.: 50-259/84-07, 50-260/84-07, and 50-296/84-07

Licensee: Tennessee Valley Authority
500A Chestnut Street
Chattanooga, TN 37401

Docket Nos.: 50-259, 50-260 and 50-296

License Nos.: DPR-33, DPR-52, and DPR-68

Facility Name: Browns Ferry 1, 2, and 3

Inspection at Browns Ferry site near Decatur, Alabama

Inspector: Ross C. Butcher — 3/20/84
G. L. Paulk — Date Signed

Approved by: F. Cantrell — 3/20/84
F. S. Cantrell, Section Chief — Date Signed
Division of Project and Resident Programs

SUMMARY

Inspection on January 26 - February 25, 1984

Areas Inspected

This routine inspection involved 128 resident inspector-hours in the areas of operational safety, licensee follow-up on previous inspection items, containment atmosphere dilution, reportable occurrences, surveillance, maintenance, physical protection, trip review, and Rosemount transmitters.

Results

Of the nine areas inspected, there were three violations and one deviation. There was one deviation in the area of "licensee follow-up" for failure to submit a follow-up report as committed to; there was one violation in the operational safety area for use of incorrect Kf factor for determining MCPR; and two violations in the area on containment atmosphere dilution for limiting conditions for operation violation and failure to follow procedure.

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REPORT DETAILS

1. Persons Contacted

Licensee Employees

G. T. Jones, Power Plant Superintendent
J. E. Swindell, Assistant Power Plant Superintendent
J. R. Pittman, Assistant Power Plant Superintendent
L. W. Jones, Quality Assurance Supervisor
W. C. Thomison, Engineering Section Supervisor
A. L. Clement, Chemical Unit Supervisor
D. C. Mims, Engineering and Test Unit Supervisor
A. L. Burnette, Operations Supervisor
Ray Hunkapillar, Operations Section Supervisor
T. L. Chinn, Plant Compliance Supervisor
C. G. Wages, Mechanical Maintenance Section Supervisor
T. D. Cosby, Electrical Maintenance Section Supervisor
R. E. Burns, Instrument Maintenance Section Supervisor
J. H. Miller, Field Services Supervisor
A. W. Sorrell, Supervisor, Radiation Control Unit BFN
R. E. Jackson, Chief, Public Safety
R. Code, QA Site Representative Office of Power

Other licensee employees contacted included licensed reactor operators and senior reactor operators, auxiliary operators, craftsmen, technicians, public safety officers, quality assurance, quality control, and engineering personnel.

2. Management Interviews

Management interviews were conducted on February 16 and 29, 1984, with the Power Plant Superintendent and/or Assistant Power Plant Superintendents and other members of his staff. The licensee was informed of three violations and one deviation identified during this report period.

Media attention this month has involved concerns about the site alert on February 14, 1984, and the Interim Reliability Evaluation Program: Analysis of the Browns Ferry Unit 1 Nuclear Plant, NUREG/CR-2802 of July 1982.

3. Licensee Action on Previous Inspection Findings

a. (Open) Violation (259/82-11-01) Drawing inadequacy related to reactor water cleanup system test line supports. The response to this violation, dated August 4, 1982, committed to an evaluation of similar safety-related line supports for Units 1 and 2 and reporting results to the NRC by January 17, 1984. As of February 25, 1984, no evaluation results have been submitted. The Plant Superintendent was informed that this item was a deviation from a commitment. (259, 260/84-07-01).

b. (Closed) Open (259/83-27-02) Loose conduit supports on EECW pressure switches 67-54 and 67-55. The licensee resupported the conduits to clear this item.

c. (Closed) Open (259/83-27-04) Electrical Maintenance Instruction 4 as related to battery maintenance was unclear on certain procedural steps. The licensee has made changes to the EMI 4 to reflect actual maintenance procedural steps. This item is closed.

d. (Closed) Violation (259/260/296/83-33-01) Cable tray seismic restraints were not installed in accordance with plant drawings. A licensee survey and repair program was conducted to correct all deficiencies. All deficiencies were corrected. A work item has been placed on the outage schedule to be performed at the end of each unit outage before startup to assure all cable tray restraints are installed. This item is closed.

e. (Closed) Open (259/83-35-01) Management Involvement in Work Activities - Long term follow-up of implementation. This item is closed and will be tracked with the licensee Regulatory Performance Improvement Program.

f. (Closed) Violation (259/260/296/83-44-01) Subcontractor employee overexposure. A review of dose rate records for all Browns Ferry employees was conducted. No other employees were found to have exceeded any dose limits. This item is considered closed.

g. (Closed) Violation (259/83-52-02) No PORC review of Industrial Security Program was conducted. PORC reviewed the program to meet the annual review requirements of Technical Specifications. This item is closed.

h. (Closed) Violation (259/83-57-01) Failure to follow special work permit radiation protection procedures. The licensee took corrective action to correct the personnel deficiencies. This item is closed.

i. (Closed) Violation (259/83-57-02) RWCU pump room 1-B was not locked, although a high radiation area. The cause was due to personnel error and corrective action was taken by the licensee. This item is closed.

4. Unresolved Item

There was one new unresolved item as noted in paragraph 5.

5. Operational Safety

The inspectors kept informed on a daily basis of the overall plant status and any significant safety matters related to plant operations. Daily discussions were held each morning with plant management and various members of the plant operating staff.

The inspectors made frequent visits to the control rooms such that each was visited at least daily when an inspector was on site. Observations included instrument readings, setpoints and recordings; status of operating systems; status and alignments of emergency standby systems; purpose of temporary tags on equipment controls and switches; annunicator alarms; adherence to procedures; adherence to limiting conditions for operations; temporary alterations in effect; daily journals and data sheet entries; and control room manning. This inspection activity also included numerous informal discussions with operators and their supervisors.

General plant tours were conducted on at least a weekly basis. Portions of the turbine building, each reactor building and outside areas were visited. Observations included valve positions and system alignment; snubber and hanger conditions; instrument readings; housekeeping; radiation area controls; tag controls on equipment; work activities in progress; vital area controls; personnel badging, personnel search and escort; and vehicle search and escort. Informal discussions were held with selected plant personnel in their functional areas during these tours. In addition, a complete walkdown which included valve alignment, instrument alignment, and switch positions was performed on the containment atmosphere dilution system and Residual Heat Removal Service Water (RHRSW) system.

During this reporting period, several plant events occurred as listed below:

a. Unit 3 continued in a refueling outage with decreased manning due to the need to implement the management improvement plan. The regulatory improvement plan is currently being implemented by the licensee.

b. A site alert was issued on February 14, 1984. This item is discussed in paragraph 7.

c. Unit 1 scrammed at 9:28 on February 9, 1984, due to a burned-up coil in a main steam isolation valve and a surveillance instruction being run on an opposite channel. The defective coil was replaced and startup began with the reactor critical at 5:28 on February 10, 1984.

d. Units 1 and 2 were operated at power during this period, except as noted in c. above, until February 14, 1984, when both units were placed in cold shutdown due to inadequate design of the residual heat removal service water pump discharge air release valves. This matter is addressed in paragraph 7.

e. During EN DES safety evaluation for RHRSW and Emergency Equipment Cooling Water (EECW) systems conducted on February 20, 1984, it was noted that the north header EECW vacuum priming valve, Nash J-36096, was not qualified to perform its intended design function. (See paragraph 7)

f. During the restart of Unit 2 at 0057 on February 22, 1984, the reactor scrammed on HI-FLUX when channels 'C' and 'F' of the intermediate range monitors spiked causing a neutron monitoring system scram. The scram occurred due to the failure of the nuclear engineer to identify on the rod pull sheet that rod 10-19 was a high worth rod. Unit 2 restarted at 8:46 on February 22, 1984, and was critical at 10:30 on February 22, 1984.

g. Unit 1 scrammed from 7.6% power during restart at 10:10 on February 22, 1984, due to main turbine first stage pressure high. Shell warming was in process during the event. Cause was attributed to excessive shell warming first stage pressure. Unit 1 restarted and was critical at 7:35 on February 22, 1984 and on-line at 2:36 on February 23, 1984.

During a databank review of Unit 1 process computer data conducted by TVA Nuclear Control Office Core Methods Section, an error was detected in the Kf breakpoint factor used in the plant process computer for calculation of the Minimum Critical Power Ratio (MCPR). MCPR is required to be determined daily during power operation greater than 25% per Technical Specification 4.5.K. The Kf factor is used to correct the MCPR for reduced flow operation. Figure 3.5.2 of Technical Specifications is a graph of Kf versus core flow for various recirculation pump motor generator scoop-tube setpoint calibrations. The plant was operating with a calibration such that flowmax was equal to 107% requiring a .80 Kf break point.

However, an incorrect Kf of .75 was loaded into the computer which resulted in nonconservative calculations of the MCPR limit from the beginning of the cycle startup on December 29, 1983 until January 30, 1984. Initially, the computer was loaded with a General Electric tape for the beginning of cycle six data per Program Modification Request (PMR) BF 83-025 on November 29, 1983. This data reflected reduced core flow of 102.5%. On December 20, 1983, the Kf factor was corrected to .80 during the performance of Refueling Test Instruction 13 (Open Vessel Plateau) and signed off in the Master Refueling Test Instruction (MRTI). A backup core dump was not made at this time. Prior to startup, computer problems occurred necessitating reloading the computer. Again, the beginning of cycle six data was loaded but the Kf correction was not made.

A violation of 10 CFR 50, Appendix B, Criterion V occurred in that Standard Practice 23.1 (Nuclear Digital Computer Software Systems) was not adequately accomplished to control the Kf break point factor used in the MCPR calculations. The plant superintendent was notified of this violation in an exit meeting on February 29, 1984. (259/84-07-02) Also, an unresolved item concerning computer software change control was discussed as addressed below.

A potentially generic problem exists in the control of software changes to the plant process computer. The computer is used to insure various thermal limits are acceptable as specified in Technical Specifications.

Presently, a procedure, Standard Practice 23.1 (Nuclear Digital Computer Software Systems), exists to cover software changes but does not specifically cover all changes made to the computer. Two groups, computer specialists and the nuclear engineers, make software changes to the computer. The computer specialists work the day shift only and the nuclear engineers work various shifts depending on plant operation. Changes are often made by the nuclear engineers without any record and unbeknown to the computer specialists.

Further, problems may occur with the computer operation during the night which are not identified to the computer group. Training of personnel in the control of computer oper--ions also appears inadequate.

Due to the potential impact of incorrect calculations of thermal limits, this item is unresolved pending further investigation by the licensee and inspectors. (259/84-07-03)

6. Containment Atmosphere Dilution System

In normal operation, the primary containment atmosphere is maintained at less than 4.0 percent oxygen by volume, with nitrogen. Following a loss-of-coolant accident, hydrogen may be evolved within the containment from metal-water reactions. Hydrogen and oxygen are produced by radiolysis of water. These are the only significant sources of hydrogen and oxygen. If the concentrations of hydrogen and oxygen were not controlled, a combustible gas mixture could be produced. To ensure that a combustible gas mixture does not form, the oxygen concentration is kept below 5 percent by volume or the hydrogen concentration is kept below 4 percent by volume.

The concentration of combustible gases in the containment following a loss-of-coolant accident is controlled by a Containment Atmosphere Dilution (CAD) system. The system would be operated to maintain either the hydrogen concentration below 4 percent or the oxygen concentration below 5 percent.

The CAD system nitrogen supply facilities include two trains, 'A' and 'B', each of which is capable of supplying nitrogen through separate piping systems to the drywell and suppression chamber.

The nitrogen storage tanks have a nominal capacity of 3000 gallons each, which is adequate for CAD operation. The gas above the nitrogen liquid in the CAD tank is maintained at a minimum pressure of 100 psig.

The CAD system is operated manually. Following a LOCA, records are kept of hydrogen and oxygen concentrations and pressures in the drywell and suppression chamber, and calculations are made of the production rates of hydrogen and oxygen. Nitrogen additions are made periodically as needed to keep the oxygen content below 5 percent of each volume. Additions are made separately to the drywell and the suppression chamber as needed. Thus, the CAD system lineup errors noted below could have been corrected prior to any required usage of the system.

On January 25, 1984, the two CAD tanks were refilled with nitrogen from a local vendor. The plant operations staff refilled the tanks in accordance with Operating Instruction 84. The evolution was completed and the system returned to service. On January 26, 1984, a control room operator observed the CAD system pressure reading low (100 psig) on the control room pressure indicators. The operator initiated an emergency maintenance request to evaluate the apparent low pressure reading. The CAD pressure indicators typically read 120-130 psig. The CAD tank pressure is required to be greater than 100 psig by plant procedures and the Final Safety Analysis Report Section 5.2. The emergency maintenance request was worked on January 27, 1984, at 7:00. At 7:30, two valves (0-84-506 and 0-84-556) in the tank pressure buildup circuit were found isolated. One of the valves was on CAD system 'A' and one valve was on CAD system 'B'. The pressure buildup circuit takes liquid nitrogen from the bottom of the CAD tank and vaporizes it through a buildup pressure coil and regulator to the top of the CAD tank to maintain system pressure. System leakage or usage would decrease the tank pressure and with the pressure buildup circuit isolated, system pressure would decrease below 100 psig. the two valves were isolated during the fill procedure on January 25, 1984, due to the operator failing to follow the OI-84 procedure. The procedure did not require the pressure buildup valves to be isolated. The failure to follow procedure resulted in both CAD systems being inoperable for approximately 40 hours. The Assistant Plant Superintendent was informed to two violations (Violation of T.S. 3.7.G.2 and T.S. 6.3.A.1) in this area on February 16, 1984. Units 1 and 2 were operating at power and Unit 3 was in an outage during this event. (259/260/84-07-04 and 05).

7. RHRSW/EECW Air Release Valve Design Deficiency

During a routine safety tour on February 3, 1984, the inspector noted that the "B" Residual Heat Removal Service Water (RHRSW) pump room was flooding. Further investigation indicated that the flooding was due to failure of the "B-3" Emergency Equipment Cooling Water (EECW) System pump air release valve located on the pump discharge line. The pump room had flooded to the 2-foot level prior to the pump being secured. The Plant Superintendent was immediately informed of the inspector's finding in this area. The following details are provided as background for this event:

a. Flooding of Residual Heat Removal Service Water (RHRSW) pump room on August 22, 1981 (I.E., Report 50-269/260/296/81-28 excerpt).

   On August 22, 1981, the "A" RHRSW pump room was flooded to a level of 6½ feet which resulted in the three RHRSW pumps in this room being made inoperable. (LER 259/81-47) The cause was attributed to failure of the air vacuum valve associated with RHRSW pump A2 to properly seal after the pump was placed into operation. Water leakage past the valve exceeded the capacity of the two sump pumps located in the room. The three RHRSW pumps were not damaged although water was found in the pump oil. Maintenance was performed on transmitters which had been flooded to return them to an operable condition.

The inspector reviewed the details of the flooding incident which included the history of maintenance on the air vacuum valves. The findings included the following:

(1) The air vacuum valves in service on the 12 RHRSW pumps were made by two different manufacturers, 6 by Valve and Primer Corporation (APCO) and 6 by Crispin Manufacturing. Both are float type valves where the float rises to seat against a rubber sealing material. The main difference is that the APCO valves have floats with guide tubes on the upper and lower ends. The Crispin valve has a float weighted on one end and no guide tubes.

(2) Three of the APCO valves had the upper guide bar missing including the valve assigned to pump A2. The bar, about 3 inches in length, had broken off at both ends. From examination of the break surface, TVA concluded that the bars had been missing for a long period of time.

(3) Inspection verified that floats in valves with the upper guide bar missing could come free from the lower guide and be subject to force which caused varying degrees of deformation. Float seating was adversely affected.

(4) The maintenance record card for the valve associated with pump A2 revealed that the rubber valve seat was replaced on May 15, 1981 and again on July 7, 1981 to correct valve leakage. Valve maintenance over the years has been performed by "skill of the trades" method without the benefit of written procedures or manuals. There was no evidence that personnel recognized during maintenance that the guide bar was missing on some valves or if they did, that such a condition was identified as a defective component.

(5) The practice that has been in existence is to rotate the float, with verbal concurrence of the vendor, on occasions where the top of the float is deformed and the bottom is not damaged and thus make a better sealing surface. Although the float is not symmetrical, TVA stated that the vendor advised that it would function either way.

(6) Attached to the side of the large air vacuum valve is a small air relief valve to vent small releases of air during pump operation after the large valve has seated. On some of the small valves, the vents were plugged and on others, the vents were covered with insulation. The detrimental effect of having these small valves inoperable was not yet determined.

(7) The failed valve from pump A2 was sent to TVA metallurgical staff for evaluation of the broken or missing guide bar and of a small hairline crack observed at the base of the valve. The report indicated fatigue.

(8) Another problem identified by TVA was that the flood switches in the "A" room did not appear to function properly. A wiring error was found which prevented the system from alarming at the 2 inch level. An alarm that did come in during the room flooding was apparently initiated at the 18 inch level when the transmitter for the level sensor was flooded. There was no evidence that the switches had been tested since they were installed in 1973. The wiring error was corrected and an annual test program was established.

The above findings revealed in 1981, that there had been a history of air vacuum valve failures with repeated float and seal damage occurring and of missing upper guide bars without adequate problem identification or corrective action taking place until the recent flooding incident of August 22, 1981. Another adverse finding was that the vents for some of the small air relief valves had been plugged or covered with insulation. Inspection Report 81-28 included a violation of 10 CFR 50, Appendix B, Criterion XVI for failure to identify and take corrective action on conditions adverse to quality.

b. The inspector reiterated his concerns in the area of RHRSW/EECW system reliability as related to failed air release valves in Inspection Report 50-259/260/296/82-19 as delineated below:

"During the walkdown of the RHRSW system, the inspector noted that the air vacuum valve on the A2 RHRSW pump discharge side pipe had a broken upper float guide bar. The air vacuum valve was previously replaced in August 1982, due to the same failure. In August 1981, the float became jammed during the pump operation and the discharged water from the valve flooded the "A" RHRSW pump room. Details are delineated in the Inspection Report 81-28. The licensee established recurrence control by setting up reinspection of air vacuum valves on an operating cycle basis. Next operating cycle will be the August 1982 Unit 2 refueling outage. The valve has failed prior to the reinspection schedule established, therefore, the inspector requested a reevaluation of the inspection interval to assure proper system operation. The Plant Superintendent responded that the inspection interval would be reviewed. The air vacuum valve was repaired and system returned to full service." (Open Item 259/260/296/82-19-01)

c. Region II expressed additional elevated concerns in regard to the lack of sufficient management controls and attention to the mechanical maintenance area in regard to RHRSW/EECW air release valve failures in I.E. Inspection Report 50-259/260/296/83-15. Additionally, I.E. Report 83-15 included a second violation and first deviation related to this area. Excerpts from I.E. Report 83-15 listed below point out those concerns:

"During a walkdown of the RHRSW system on March 28, 1983, the inspector noted that the air vacuum valve on the A3 RHRSW pump discharge side pipe had a broken upper float guide bar. In August 1981, a similar failure caused the float to become jammed during the A2 pump operation and water discharged into the "A" RHRSW pump room flooding the room. The flooded pump room caused three of the twelve available RHRSW pumps to become inoperable. Similar air vacuum valve failures had been known to the licensee prior to August 1981, however, no prompt corrective action had been taken to assure adequate quality standards were met. Thus, a violation of 10 CFR 50, Appendix B, Criterion XVI, was issued in Inspection Report 81-28 (259/81-28-09, 260/81-28-06). In TVA's response of November 27, 1981, to Inspection Report 81-28, Violation B, the licensee committed to scheduling a maintenance action to inspect air vacuum valves every operating cycle. Unit 2 completed a 231 day refueling/operating cycle on March 20, 1983. A review of records and discussions with plant maintenance staff indicates that the commitment to maintenance action was not conducted for the Unit 2 operating cycle. After discussions with the resident inspector, the licensee has taken action to conduct the maintenance action as committed to in response to Violation 259/81-28-09, 260/296/81-28-06 of Inspection Report 81-28. The Plant Superintendent was informed at the exit meeting of April 22, 1983, that failure to conduct maintenance inspection of RHRSW air vacuum valves as committed to in response to Inspection Report 81-28 was a deviation from a commitment to the Commission (259/260/296/83-15-01).

Additionally, the inspector informed the Plant Superintendent at the exit meeting on April 22, 1983, that problems with the RHRSW air vacuum valves are a deficient area and increased management attention should be addressed to this area. The continuing problem with RHRSW air vacuum valves was brought to the attention of the licensee in Inspection Report 82-19 (Open Item 259/260/296/82-19-01). At that time, the inspector had informed the licensee of a failed air vacuum valve on the A2 RHRSW pump found during an operational safety tour by the inspector. The Plant Superintendent committed to evaluating the inspection interval of the air vacuum valves. The inspector could find no indication to date that an evaluation has been completed. Specifically, in response to the management control concerns, the licensee should address:

(1) Corrective actions to be taken to assure commitments are tracked and compliance assured.

(2) Corrective actions to be taken to correct potential loss in reliability of RHRSW system due to repetitive failures of RHRSW air vacuum valves.

(3) Corrective actions to assure communication/procedures are clarified between maintenance and operational areas.

(4) Management attention to be taken that will assure compliance and increased plant safety reliability.

d. Background on RHRSW/EECW System

The licensee conducted a failure evaluation of the air release/vacuum relief valves to determine impulse loading requirements during pump starts. The evaluation was completed on February 18, 1984. A brief description on system operation and the evaluation follows:

The twelve RHRSW/EECW pumps are housed in the intake pumping station, which is located on the edge of the Wheeler Reservoir. These pumps are arranged in four watertight compartments, with one RHRSW pump, one EECW pump, and one swing pump (normally aligned to (RHRSW) in each compartment. The intake pumping station deck is at plant grade (elevation 565'). Each compartment, however, is designed to be watertight up to elevation 578' in order to protect the pumps in the event of an external flood which rises above elevation 565'. Watertight doors are provided for personnel access to each compartment. This same watertight protection which protects against an external flood may pose a problem from an internal flooding perspective. In the event of a release of water in the compartment that exceeds the capacity of the drains and sump pumps, the compartment could be flooded and thereby fail all three pumps in that particular compartment. Such an event occurred on August 22, 1981 (reference BFRO 50-259/81-47) when an RHRSW pump discharge air and vacuum release valve failed with the pump running and flooded the room rendering all three pumps in that compartment inoperable.

Each pump is equipped with an air and vacuum release valve at the pump discharge, which is designed to vent air from the system upon pump start. Failure of this valve to close upon pump start could result in a release of water to the room and a corresponding reduction of flow to the header. Several releases of water in this manner have occurred but only the event mentioned above actually caused flooding to the extent that all three pumps failed. Beyond the aspects of flooding, the diversion of flow through a failed air release valve must also be considered. The air and vacuum release valves are mounted on a 4-inch flange and spool piece which is connected to a 14-inch (EECW) or 18-inch (RHRSW) header. The discharge flow area of the air and vacuum release valves is estimated to be equivalent to a 2-¼-inch opening if the valve fails in the full open position. Hydraulic calculations indicate that a significant flow diversion would result if either the valve stuck open (approximately 23 percent of rated flow) or the valve separated from the 4-inch flange (approximately 90 percent of rated flow). Either of these failure modes would in effect, fail the respective pump by reducing flow to the header.

Not all valve failures result in a significant release of water to the room or in a failure of the associated RHRSW/EECW pump. Past experience indicates (see Table 1) that most of the failures involving leakage were the result of the valve float failing to seat correctly. Most of these incidents did not result in a significant diversion of flow. Valve failures also contribute to RHRSW/EECW pump unavailability due to maintenance, since the pump must be taken out of service in order to repair the valve.

Sufficient redundancy exists within the RHRSW and EECW systems such that the loss of three pumps due to one event would not in itself cause either system to fail. It would, however, degrade the systems such that an additional failure could result in a system failure. It should be noted that the RHRSW system and the EECW system are not redundant systems; they perform different functions, both of which are required to bring the plant to a safe shutdown condition. Under the most severe conditions, (e.g., a loss of offsite power with three units operating) the flow requirements can be met by six RHRSW and three EECW pumps. Under less severe conditions or with less than all three units operating, flow requirements can be met by fewer pumps.

In addition to the concern for a failure of a pump or pumps due to air and vacuum release valve failures, a flooded compartment would complicate possible recovery actions. For example, if only two EECW pumps were operating during a loss of offsite power transient, one of the swing pumps could be valved over to EECW service. However, the flooding event would disable one of the swing pumps that otherwise could have been used.

The past operating history of the air and vacuum release valves indicate that they are significant contributors to both the RHRSW/EECW pump failure on demand frequency and the overall pump unavailability due to maintenance. Modifications to the air and vacuum release valves are planned which will greatly improve the reliability of these valves. In the interim, the licensee has added an orifice to the four-inch line which would limit the flow in the event of a failed valve. Loss of flow would be limited to the extent that even with a valve failure, RHRSW/EECW pump flow requirements could be met.

Compartment flooding due to valve malfunction will still be possible, but at a much slower rate of fill, with the installed orifice. As an interim measure, the pump compartment watertight doors will be left open in order to eliminate the concern for compartment flooding from internal sources.

Modifications are planned by the licensee to replace the current air release valve with a higher pressure rated surge check air release valve.

An in-depth evaluation of the ability of the Emergency Equipment Cooling Water (EECW) and Residual Heat Removal Service Water (RHRSW) systems to meet their design bases was completed by the licensee on February 20, 1984. This evaluation revealed the following:

(1) EECW vacuum priming valve located on the north EECW header, Unit 3, had no specified pressure rating and is generally used in non-safety-related systems. Design analysis indicated this valve

was not qualified for system operation and the licensee valved out the component until a final measure can be taken.

(2) Nine RHRSW/EECW system components were found to not be acceptable for some design loading combination or design conditions. However, a functional impairment of the component was not likely.

(3) The twelve RHRSW/EECW air release valves were found to have inadequate design pressure ratings for system operation. Interim and final corrective measures are discussed above. The operating units were shutdown on February 13, 1984, to provide an interim repair to the air release valves. Table 1 describes previous known failures or deficiencies with the air release valves.

The inspector will continue to follow the details related to this event to assure regulatory requirements are met. (Open Item 259/84-07-06).

e. Conclusion

The above summary gives indication of the following noted licensee deficiencies as related to management control and licensee interfaces with other TVA organizations. The inspector's concerns are delineated below:

(1) Design evaluations of system operability and bases are generally inconclusive, shallow-in-depth, slow in response, and lacking in sufficient detail to ascertain operability requirements. The RHRSW/EECW system has had other evaluations conducted on it in the past which, as demonstrated by the latest evaluation, were inadequate.

(2) The air release valve design pressure rating problem was identified due to a plant initiated design change request (DCR 2910) to change the air release valve due to NRC concerns about the reliability of these valves and the increased surveillance of the valves due to commitments to the NRC and general plant preventative maintenance.

(3) The root cause of the air release valve problem was discovered 2½ years after the concerns were first brought to the licensee management's attention (I.E. Report 81-28). Root cause determination lacks initiative and responsiveness.

Similar problems have been noted as referenced in numerous inspection reports as violations and deviations of NRC requirements. Increased attention to management controls, to the openness of communication channels between TVA divisions, and to the thoroughness of follow-up actions at the plant should improve the deficiencies and concerns noted above.

f. SITE ALERT on February 14, 1984

On Feburary 13, 1984, the Plant Superintendent became aware that a design deficiency existed with the air release valve on the discharge of each RHRSW pump. The valves were not adequately pressure-rated for system operation. A design change reque.t (DCR 2910) was initiated by the plant on August 10, 1983, to add a surge check valve on the inlet side to the air release valve to minimize water hammer and pressure surges. The design change request was specifically initiated due to increased NRC concern as evidenced by the aforementioned sections and the DCR justification section. Final design review was completed on February 18, 1984, that indicated the originally designed air release valves were deficient.

On February 13, 1984, the Plant Superintendent, based on preliminary data, decided to shut down the two operating units (1 and 2), due to the apparent design analysis concerns. Unit 3 was in a refuel outage.

At 8:30 a.m., with the plant at less than 50 psig and approximately 220°F, while trying to initiate shutdown cooling on Unit 1, the operator could not open shutdown cooling inboard suction valve (FCV 74-48). Plant procedures require an alert be initiated when there exists a loss of shutdown cooling. At 9:30 a.m., de-inerting of the drywell began in preparation for manual valve operation. Cold shutdown was achieved at 10:08 a.m., through normal cooldown to the condenser, using the control rod drive system pumps to inject water and the reactor water cleanup system as an alternate method for residual heat removal. Emergency core cooling systems (low pressure coolant injection and core spray) were available thoughout the event. In addition, the condensate system was also available for reactor makeup and both high pressure coolant injection and reactor core isolation cooling could have been made available by using auxiliary steam if required. The inboard shutdown cooling valve was manually opened at 5:17 p.m., on February 13, 1983 and the normal path of shutdown cooling established. Failure of FCV 74-48 was due to an electrical failure, motor burnout. The alert was secured at 5:25 p.m. All other Unit 1 systems performed as designed. There was no danger to the public at any time during the event.

8. Maintenance Observation

During the report period, the inspectors observed the below listed maintenance activities for procedure adequacy, adherence to procedure, proper tagouts, adherence to Technical Specifications, radiological controls, and adherence to quality control hold points.

a. Raw cooling water pipe break near off gas building - common.

b. Units 1 and 2 pipe hangar repairs on various components - Condensate transfer pipe cable support replaced.

c. HPCI flow recorder - Unit 2.

d. Oil analysis and changeout - Standby liquid control pumps.

e. RHRSW air release valve orifice modifications.

f. Rosemount transmitter changeout on U-1 - Main steam line high flow system. (see Section 13)

No violations or deviations were found in the above areas.

9. Plant Physical Protection

During the course of routine inspection activities, the inspectors made observations of certain plant physical protection activities. These included personnel badging, personnel search and escort, vehicle search and escort, communications and vital area access control.

No violations or deviations were identified within the areas inspected.

10. Surveillance Testing Observation

The inspectors observed and/or reviewed the below listed surveillance procedures. The inspection consisted of a review of the procedure for technical adequacy, conformance to Technical Specifications, verification of test instrument calibration, observation on the conduct of the test, removal from service and return to service of the system and a review of test data.

a.	S. I. 4.10.D.1	Reactor building crane - common
b.	STEAR 82-11	HPCI throttle valve test - Unit 2
c.	S. I. 2	Operator Logs
d.	Standard Practice 23.1	Computer entries to meet Technical Specification requirements. (see Section 5)

No violations or deviations were noted in the above area.

11. Scram Trip Review

Unit 2 scrammed at 10:06 a.m., on November 10, 1983 from 97.5% power during the performance of a surveillance instruction on main steam line high flow instruments. While testing the 'B' channel switch, it was accidentally jarred, causing a second and spurious 'A' channel trip. A main steam line isolation occurred and on double low reactor water level, High Pressure Coolant Injection (HPCI) and Reactor Core Isolation Cooling (RCIC) received auto start signals. However, HPCI immediately isolated due to a failed rupture disc. Seven Main Steam Relief Valves (MSRVs) were operated manually about 2 minutes per valve, to control pressure. RCIC ran an estimated

20 minutes and the MSIVs were reopened in 12 minutes. The 'A' channel MSL flow switch (PdIS-1-13A) was replaced. Further testing of HPCI and a report is expected by March 30, 1984, concerning the rupture disc failure. All safety systems responded as required with exception of the HPCI system as noted. (LER BFRO-50-260 83074 R2)

On November 15, 1983, at 8:25 p.m., Unit 2 reactor tripped from 73% power. Following a load reduction for maintenance on 2A reactor feed pump, the operator inadvertently closed the 2B feed pump suction valve resulting in a reactor trip on low water level. At double low level, the main steam lines isolated and other safety systems operated normally. Four MSRVs were manually actuated to control reactor pressure. The MSRV tailpipe temperature recorder did not function as the chart paper did not advance and the HPCI/RCIC flow recorder (FR-71-36) did not indicate HPCI flow (HPCI flow was verified by operations). Following the scram, high off-gas flow created an airborne contamination situation in the turbine buildings. Apparently high off-gas flow in Unit 2 created a backflow surge through the Unit 3 condensate drain tank vent and the condensate drain tank overflow loop seal through the turbine building drain system. The turbine seals and equipment drains on Unit 3 were open to atmosphere as a result of outage related work. Public health and safety were not affected by the above events. All safety systems operated normally with exception of the recorders as noted above.

Unit 2 scrammed on December 10, 1983, at 11:35 p.m., from 60% power. The cause of the scram was due to low condenser vacuum caused by isolation of the steam jet air ejector due to maintenance on the off-gas holdup volume temperature alarm. All safety systems responded as designed.

December 21, 1983 at 9:45 a.m., Unit 2 scrammed from 99.8% power. The reactor automatically scrammed when the A2 and B2 reactor trip actuators de-energized from an unknown cause. The exact cause could not be determined but the instrument mechanics were calibrating reactor vessel level instrument LIS-3-56D. RCIC was started manually to maintain level for five minutes. All safety systems operated as required.

Unit 1 reactor was manually scrammed from 13.5% power at 11:42 p.m. on January 6, 1984. The turbine was operating unloaded when vibration problems occurred and condenser vacuum was broken to slow the turbine. The mode switch was taken to startup to avoid the condenser low vacuum scram and control rods were inserted to reduce reactor power. During the control rod insertion, the nuclear engineer realized an improper rod manipulation took place and recommended a scram which was conducted. (Reference Inspection Report 84-02). All systems performed as designed.

On February 9, 1984, at 0925 a.m., Unit 1 scrammed from 99% power during the performance of a surveillance instruction on main steam line high radiation trip instruments. One channel of the reactor protective system was tripped per the instruction and the AC solenoid power was removed from a Main Steam Line Isolation (MSIV) valve. Unknowingly, the DC solenoid power had previously failed on this valve and the loss of both power supplies resulted in the 'C" MSIV outboard valve FCV-1-38 closing. This tripped the other channel of the reactor protective system on high pressure and resulted in a reactor scram. Also main steam line high flow signals occurred resulting in a full MSIV closure. Three MSRVs were operated manually to control pressure for less than one minute. All other systems operated as designed.

A manual scram was conducted on Unit 1 from 45% power at 0245 a.m. on February 14, 1984, due to a management decision to shut down the unit. Inadequate design of the RHRSW/EECW air release/vacuum relief valves was the basis. RHR inboard isolation valve 74-48 did not open when an attempt was made to place the residual heat removal system into shutdown cooling. Both of these items are addressed separately in other sections of this report. All other systems performed as intended.

Unit 1 scrammed at 10:10 a.m., on February 22, 1984, from 7.6% power during turbine warming operations. During warm-up, first stage pressure exceeded 142 psig with the turbine stop valves closed. The setpoints of PT-1-81B and 1-91A were reached resulting in a reactor trip as the purpose of the reactor trip is for a turbine trip when greater than 30% power as sensed by first stage pressure. All systems performed as designed.

12. Reportable Occurrences

The below listed Licensee Event Reports (LERs) were reviewed to determine if the information provided met NRC requirements. The determination included: adequacy of event description, verification of compliance with Technical Specifications and regulatory requirements, corrective action taken, existence of potential generic problems, reporting requirements satisfied, and the relative safety significance of each event. Additional inplant reviews and discussion with plant personnel as appropriate were conducted for those reports indicated by an asterisk. The following licensee event reports are closed:

LER No.	Date	Event
296/83-50	8-09-83	Pressure switch for torus to reactor building vacuum breaker out of limit.
296/83-51	8-12-83	Control valve closure/stop valve scram bypass pressure switches out of tolerance
*296/83-52	8-16-83	Diesel generator 3 ED failed to reach rated speed on start
296/83-53	8-31-83	Hydrogen analyzer 'B' inoperable.
*296/83-54	9-19-83	MSIVs exceeded allowable leak rate

296/83-56	9-29-83	Reactor high pressure instrument drift
*296/83-57	10-10-83	Refueling interlock inoperable
296/83-58	10-17-83	Drywell temperature recorder out of calibration
*296/83-60	12-14-83	Target Rock relief valve relief test not within tolerance
*296/84-01	1-03-84	Diesel generator 3 ED cooling water flow blockage due to clams

No violations or deviations were noted in the above area.

13. Rosemount 1153 Pressure Transmitters

During the last refueling outage, the licensee installed the new analog trip system on the Unit 1 main steam line high flow sensing system. Rosemount 1153DP transmitters were used in the system. Since system installation and unit startup there have been numerous failures noted with the system as indicated by Table 2. Generally, the failures are in the non-conservative direction (downscale). The cause of the downscale failures has been unknown since plant startup on December 29, 1983. The inspector has expressed his concern to plant management. The licensee is taking action to investigate the cause of the failures. The licensee was aware of problems in this area, although the attached table of maintenance actions had not been generated or tracked by the licensee until requested by the inspector.

A special meeting concerning corrective actions and probable causes has been requested by the NRC and will be held March 6, 1984. This item will remain open for further follow-up. (259/84-07-07). Licensee Event Report 259/84-08 discusses related failures.

TABLE I

Component: Air and Vacuum Release Valve

Failure Mode: Failure to Operate on Demand

- Component population: Twelve
- The number of demands on the valve is equivalent to the number of RHRSW/EECW pump starts. This number is approximately 3920 component demands for the period of August 1974 to January 1984. (As calculated by the licensee).
- Failure data for the given failure mode:

Date	Reported Failure
Before 1977	Maintenance records inconclusive
12/14/77	Damaged float on 23-590
04/21/78	Excessive leakage through 23-545
09/20/78	Float and seat bad on 23-545
10/20/78	Float hung on 23-590
03/06/80	Float not seating correctly on 23-560
11/19/80	23-545 leaking
02/16/81	23-505 won't close
08/23/81	23-505 broken
09/01/81	Damaged float on 23-590
09/01/81	Damaged float on 23-545
09/03/81	Bad seat on 23-593
07/11/81	23-505 float seat torn off
11/24/81	23-541 leaking
11/30/81	Float not seating correctly on 23-590
12/22/81	Worn gasket on 23-505
06/18/82	23-505 broken
07/23/82	23-521 leaking
08/05/82	Damaged float on 23-596
08/17/82	Damaged float on 23-596
04/12/83	23-587 worn out
05/04/83	Replace 23-545, 23-590, and 53-596
06/02/83	Replace 23-590
07/27/83	Replace float on 23-541
08/01/83	23-501 leaking
08/04/83	23-560 leaking
08/07/83	23-590 leaking
12/20/83	23-590 leaking

TABLE 2

MAIN STEAM LINE HIGH FLOW INSTRUMENT FAILURES (ROSEMOUNT 1153)

Date	Maintenance Action (M.R. #)	Instrument Number	Work Performed
11-01-83	_____	Pdt-1-50A	Failed prior to installation. Returned to Rosemount Replaced with S/N 404998.
11-01-83	_____	1-PIS-1-50A	Failed during system checkout. Replaced with 2-PIS-1-50A.
11-19-83	129874	PIS-1-36B	Failed downscale. Replaced with 2-PIS-1-36B.
12-20-83	221188	Pdt-1-13B	Transmitter downscale. Calibrated and returned to service
12-31-83	221217	Pdt-1-13B	Installed new transmitter S/N 404997
1-12-84	221157	Pdt-1-13, 25, 36 & 50 A, B, C, D	Torqued bolts on transmitters
1-10-84	214366	Pdt-1-36B	Calibrated transmitter and returned to service.
1-10-84	216766	Pdt-1-13A	Flusher snubber. Calibrated transmitter per SI 4.2.A.7 and returned to service.
1-14-84	216959	Pdt-25B	Cleaned snubbers, bled instrument, performed calibration, returned to service.

1-15-84	207253	Pdt-1-25B	Cleaned snubbers, performed calibration per SI 4.2.A.7 and returned to service
1-19-84	207369	Pdt-1-25B	Cleaned snubbers, calibrated and returned to service
1-20-84	207380	Pdt-1-25B	Transmitter to be changed out on MR # 204189
1-20-84	204189	Pdt-1-25B	Installed new transmitter, S/N 404987, calibrated and returned to service
1-23-84	217096	Pdt-1-25A	Installed new transmitter, S/N 404987, calibrated and returned to service
1-20-84	203136	Pdt-1-13, 25, 36 & 50 A, B, C & E	Pins removed from snubbers
1-29-84	256452	Pdt-1-25B	Valved transmitter out of service and valved transmitter back in service
1-29-84	256465	Pdt-1-25B	Installed new transmitter, S/N 404992
1-30-84	261752	Pdt-1-25B	Worked in conjunction with above entry M. R. # 256465
1-30-84	261753	Pdt-1-25A	Installed new transmittter, S/N 404990
2-01-84	261827	Pdt-1-25A	Installed new transmitter, S/N 404990
2-03-84	262064	Pdt-1-25C & D	Open and Investigate problem
2-03-84	261840	Pdt-1-25A & C	Removed cover on amp

			side of transmitter, checked frequency and re-torqued
2-10-84	221171	Pdt-1-25B	Took readings with scope and count rate meter while Pdt still in downscale failure position
2-10-84	261867	Pdis-1-13 A & D	Verified setpoints of all main steam line high flow pressure switches
2-12-84	150544	Pdt-1-25B	Tightened packing nut on transmitter block valve
2-13-84	256326	Pdt-1-25B	Transmitter to be changed out on MR # 221171
2-15-84	221174	All transmitters	Bled high and low side of transmitters
2-22-84	203063	Pdt-1-13, 25, 36 & 50, A, B, C, & D	Bled air from transmitters
2-23-84	267906	Pdt-1-25A	300 MW 25A failed downscale, returned to normal when equalized
2-23-84	264381	Pdt-1-25B	Failed downscale, replaced transmitter with S/N 404999
2-24-84	251523	Pdt-1-25 A thru D	Removed snubber body from lines