UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W.
ATLANTA, GEORGIA 30323

Report Nos.: 50-338/89-35 and 50-339/89-35

Licensee: Virginia Electric & Power Company
5000 Dominion Boulevard
Glen Allen, VA 23060

Docket Nos.: 50-338 and 50-339 License Nos.: NPF-4 and NPF-7

Facility Name: North Anna 1 and 2

Inspection Conducted: November 18, 1989 - January 3, 1990

Inspectors: S.M. Shaeffer FOR 2-2-90
J. L. Caldwell, Senior Resident Inspector Date Signed

S.M. Shaeffer FOR 2-2-90
L. P. King, Resident Inspector Date Signed

Accompanying Inspector: S. M. Shaeffer, Project Engineer

Approved by: P. E. Fredrickson 2/5/90
P. E. Fredrickson, Section Chief Date Signed
Division of Reactor Projects

SUMMARY

Scope:

This routine inspection by the resident inspectors involved the following areas: plant status, maintenance, surveillance, engineered safety feature walkdown, operational safety verification, operating reactor events, licensee event report followup, and action on previous inspection findings. During the performance of this inspection, the resident inspectors conducted reviews of the licensee's backshift operations on the following days: November 18, 29, 30, December 12, 13, 14, 20, 21 and January 3.

Results:

Within the areas inspected, one apparent violation was identified which involved the loss of containment integrity (paragraph 6). A second apparent violation was identified concerning the timeliness of a decision to make a four-hour report to the NRC (paragraph 6).

A weakness was identified with regards to a lack of planning associated with maintenance being performed on safety-related equipment (paragraph 6).

A weakness was identified concerning procedure implementation of personnel safety requirements as related to emergency team response inside the containment (paragraph 6).

A weakness was identified concerning the corporate engineering's recommendations addressing the channel check criteria for the steam and feed flow instrumentation during startup when reactor power is below 20 percent (paragraph 7).

A strength was noted regarding the licensee's startup assessment in support of unit restart following a trip (paragraph 7).

A strength was noted whereby the licensee conducted startup training on the simulator for all licensed operator shift groups involved in unit restart (paragraph 7).

REPORT DETAILS

1. Persons Contacted

Licensee Employees

*M. Bowling, Assistant Station Manager
*R. Driscoll, Quality Assurance Manager
*L. Edmonds, Superintendent, Nuclear Training
*R. Enfinger, Assistant Station Manager
*D. Heacock, Superintendent, Engineering
*G. Kane, Station Manager
*P. Kemp, Supervisor, Licensing
*W. Matthews, Superintendent, Maintenance
T. Porter, Nuclear Safety Engineering Supervisor
*A. Stafford, Superintendent, Health Physics
*J. Stall, Superintendent, Operations
*R. Sturgill, Supervisor, System Engineering
V. West, Superintendent, Outage Management

Other licensee employees contacted included engineers, technicians, operators, mechanics, security force members, and office personnel.

*Attended exit interview

Acronyms and initialisms used throughout this report are listed in the last paragraph.

2. Plant Status

Unit 1 began the inspection period on November 18 operating at 100 percent power, day 122 of continuous operation. On November 21, Unit 1 performed a TAVE reduction evolution to reduce TAVE from 586.6 degrees F to 580.6 degrees F to help reduce SG tube degradation. The licensee was unable to reduce TAVE below 582.6 degrees F at a power level of 100 percent due to number 4 governor valve oscillations. Power was reduced instead to 98.7 percent which allowed TAVE to be reduced to 580.6 degrees F. On November 27, December 17 and 22, the licensee discovered one of the service air to instrument air backup supply isolation valves, 1-SA-PCV-105 or 2-SA-PCV-205, open on each occasion, allowing potential contamination of the instrument air system (see paragraph 6 for details).

On December 5, Unit 1 experienced a reactor trip due to a low low "B" SG water level. The indirect cause of the reactor trip was a secondary transient which occurred as a result of EHC pressure transients (see paragraph 7 for details). On December 12, during the initial heat up following the reactor trip, the "B" RCP tripped due to an electrical ground which developed in the pump motor (see paragraph 3 for details). On December 20, the licensee commenced the Unit 1 reactor startup following the outage (see paragraph 7 for details). On December 28, a HP technician reported to the control room that the personnel escape air lock in the equipment hatch appeared to be sucking air indicating a potential problem with containment integrity (see paragraph 6 for details). On January 3, the operators increased TAVE to 583.0 degrees F to allow reactor power to be increased to 100 percent and still maintain good control of the number 4 governor valve. Unit 1 completed the inspection period on January 3 operating at approximately 100 percent power, day 14 of continuous operation.

Unit 2 began the inspection period on November 18 operating at 100 percent power, day 194 of continuous operation. On December 1, the number 2 breaker in the H-bus pressurizer heater panel 2-EP-CB-10D was found open. The licensee is continuing to have problems with inadvertently tripped pressurizer heater breakers. During the operation of Unit 2 over the inspection period, a steadily increasing unidentified RCS leak rate was noted by the licensee. The last calculated unidentified leak rate was approximantely 0.4 gpm with a TS limit of 1 gpm. The resident inspectors will continue to monitor the status of the RCS leak rate during future inspections. Unit 2 completed the inspection period operating at 100% power, day 240 of continuous operation.

As of January 1, 1990, the Vice President - Fossil and Hydro, E. W. Harrell, became the new Vice President - Nuclear Operations. W. R. Cartwright, the previous Vice President - Nuclear Operations became the Vice President - Fossil and Hydro.

3. Maintenance (62703)

Station maintenance activities affecting safety-related systems and components were observed/reviewed to ascertain that the activities were conducted in accordance with approved procedures, regulatory guides and industry codes or standards, and in conformance with TS requirements.

On December 12, during the heatup of Unit 1 following the 7 day outage due to a reactor trip on December 5, the "B" RCP tripped due to an electrical ground which developed in the motor. The unit had to be cooled back down to allow replacement of the "B" RCP motor. The licensee used the spare motor located on site and allocated significant effort to install an oil collection facility on the motor.

During the initial planning for the motor replacement, station management had to decide which plant conditions would be put in place to allow work on the motor. The two choices involved reducing RCS inventory to a level below the RCP flange to prevent RCS leakage out of the flange during and following pump uncoupling or to maintain level in the pressurizer and use the backseat on the RCP shaft to minimize RCS leakage. The latter method had been used during the summer of 1987 to replace a RCP motor which had also developed a ground during unit heatup. However, the plant conditions were not fully evaluated and the result was the development of a void in the vessel head without the operators knowledge (see NRC Inspection Report 338,339/87-21). The first method also exhibited drawbacks in that RCS level has to be lowered into the reduced inventory condition thereby placing the RHR pumps potentially in jeopardy of loosing net positive suction head.

Station management chose the method of maintaining both level and a steam bubble in the pressurizer. The inspector reviewed the 1987 event and the the licensee's corrective actions, both the ones developed in 1987 and additional actions which the licensee initiated following their present review of the evolution. These additional actions were initiated to provide additional assurance that the same problem would not occur. The actions were determined by the inspector to be sufficient to prevent the recurrence of the 1987 event which was demonstrated by the licensee's successful performance of the evolution.

The licensee developed a procedure to control the evolution and special logs were taken on several indicators of RCS inventory to verify that level and a steam bubble were being maintained in the pressurizer. The inspector attended the briefings associated with the evolution and found them to be satisfactory.

On December 13, 1989, the inspector made an entry into the Unit 1 reactor coolant pump "B" motor cubicle to observe the uncoupling of the motor to pump shaft. This uncoupling allowed the pump shaft to drop enough to backseat the shaft and prevent excessive leakage up the shaft and to the atmosphere. The licensee was able to uncouple the pump with minimal spray and once the shaft was fully seated the leak rate was controlled at approximately 3/4 gpm. This leak rate was small enough to be directed out of a drain valve into a hose and directed to the containment sump. With the exception of some problems initiating work in the containment, the uncoupling evolution was very well performed.

The inspector periodically monitored the special logs maintained by the operators specifically for this condition, and verified that RCS level was being maintained in the pressurizer. The licensee also installed a head vent on top of the reactor vessel head and vented the head several times to ensure that no gas buildup was occurring in the vessel head. The successful performance of this evolution demonstrated that these plant conditions were more desirable than reducing RCS inventory to perform the work.

On December 20, 1989, the inspector witnessed a Motor Load Limit Test of the Unit 1 "B" accumulator outlet valve. This was accomplished as a post maintenance test using MOVATS equipment. The valve motor satisfactorily passed the test.

No violations or deviations were identified.

4. Surveillance (61726)

The inspectors observed/reviewed TS required testing and verified that testing was performed in accordance with adequate procedures, that test instrumentation was calibrated, that LCOs were met and that any deficiencies identified were properly reviewed and resolved.

On December 20, the inspector witnessed 2-PT-82J, 2J Emergency Diesel Generator Slow Start Test. The inspector did not identify any problems associated with the performance of the surveillance test.

On December 21, 1989, the inspector witnessed 2-PT-24.3, Turbine Valve Freedom Test, for Unit 2. Reactor power was reduced to 90 percent for the test and all valves were tested satisfactorily.

No violations or deviations were identified.

5. ESF System Walkdown (71710)

The Unit 2 LHSI system was verified operable by performing a walkdown of the accessible and essential portions of the system on November 30, 1989. The walkdown was completed using a copy of the most recently completed 2-OP-7.1A, Valve Checkoff - Low Head Safety Injection System. No problems were identified by the inspector.

No violations or deviations were identified.

6. Operational Safety Verification (71707)

By observations during the inspection period, the inspectors verified that the control room manning requirements were being met. In addition, the inspectors observed shift turnover to verify that continuity of system status was maintained. The inspectors periodically questioned shift personnel relative to their awareness of plant conditions. Through log review and plant tours, the inspectors verified compliance with selected TS requirements and LCOs.

In the course of the monthly activities, the resident inspectors included a review of the licensee's physical security program. The performance of various shifts of the security force was observed in the conduct of daily activities to include: protected and vital areas access controls, searching of personnel, packages and vehicles; and badge issuance and retrieval. On a regular basis, RWPs were reviewed and the specific work activity was monitored to assure that the activities were being conducted per the RWPs.

The inspectors kept informed, on a daily basis, of overall status of both units and of any significant safety matter related to plant operations. Discussions were held with plant management and various members of the operations staff on a regular basis. Selected portions of operating logs and data sheets were reviewed daily. The inspectors conducted various plant tours and made frequent visits to the control room. Observations included: witnessing work activities in progress; verifying the status of operating and standby safety systems and equipment; confirming valve positions, instrument and recorder readings, and annuciator alarms; and observing housekeeping.

As discussed in a previous NRC inspection report (338,339/89-31), Unit 1 has been experiencing an increasing unidentified leak rate. The licensee suspected the leak was coming from 1-RC-52, the "B" RCS loop RTD bypass isolation valve, since that valve had been identified as having a packing leak during the startup following the refueling outage. Attempts to stop the packing leak during the startup were unsuccessful and the licensee chose to continue with the unit startup and operation while 1-RC-52 had a slight packing leak. On November 27, the Unit 1 unidentified leak rate had increased to approximately 0.8 gpm and showed no signs of stabilizing even though the rate of increase was very slight. The licensee conducted containment entries and again concluded that the leakage was coming from the "B" RCS loop room and was attributed to 1-RC-52, although 1-RC-55 was also suspect.

On November 30, with the unidentified leak rate at approximately 0.9 gpm, the licensee conducted additional containment entries in an attempt to identify and quantify the leak rate from 1-RC-52 to allow it to be called identified. This would allow them to substract the leakage from the unidentified leak rate and add it to the identified leak rate. Attempts to quantify the leak rate from 1-RC-52 at the location of the valve were unsuccessful due to interference problems and radiation levels. The licensee then installed a tarp at the bottom of the "B" loop room to collect the leakage dripping off of the pipes, supports, etc. from above and directed that leakage to a graduated receptacle. From this method the licensee calculated the leak rate from 1-RC-52 to be approximately 0.3 gpm. This calculation reduced the unidentified leak rate to approximately 0.6 gpm. The licensee was informed that if the calculated unidentified leak rate exceeded 1 gpm, then the method discussed above for reducing the leak rate to less than 1 gpm would have to be reviewed further by the NRC. On December 1, the licensee again entered the Unit 1 containment to perform a video tape of the 1-RC-52 packing leak and any other areas of suspected leakage. The inspector viewed the tape and it was clear that the valve identified by the licensee as 1-RC-52 had a significant packing leak.

As discussed in paragraph 7 of this inspection report, Unit 1 tripped on December 5 due to problems related to the EHC system. Following the reactor trip the licensee entered a short outage to, among other things, repair the packing leak on 1-RC-52. Along with this repair, the licensee conducted tours of the containment to identify any other RCS leakage paths. During this inspection, the operators discovered that the flange on check valve 1-CH-496 had a substantial leak with RCS pressure only at approximately 90 psig. This three inch check valve is the first of two check valves located in the normal charging system header just prior to the charging system penetration into the cold leg side of "B" RCS loop. The leakage emanated from the check valve bonnet due to degradation of the fasteners from boric acid corrosion. The licensee replaced the packing on 1-RC-52, and replaced the gasket and fasteners on check valve 1-CH-496.

The following concerns were identified by the inspector regarding RCS leakage problems. The first concern involved the method used to identify the leakage rate from 1-RC-52. Since the leakage was collected in the basement of the "B" loop room, instead of directly under the suspect valve, a portion of the leakage could have come from check valve 1-CH-496. This would invalidate the licensee's ability to call the collected leakage identified. Since prior to the trip the Unit 1 RCS unidentified leak rate did not exceed one gpm total, TS requirements were always met. However, in the future, the licensee agreed that the method used to quantify a RCS leak, would ensure that all the leakage collected is from the identified source. The second concern involves the degradation of 1-CH-496 fasteners due to boric acid corrosion. The licensee informed the inspectors that their program for inspection of fasteners for degradation due to boric acid did not include components smaller than six inches. The licensee also informed the inspectors that this program would be reviewed and corrected to include all types of fasteners which may be succeptable to boric acid degradation. The inspector will continue to follow the licensee's implementation of this issue.

On December 22, the licensee informed the inspectors of a problem concerning the failed Unit 1 "B" RCP motor while being transported by truck to the Westinghouse plant in Pennsylvania. Approximately two miles from the Westinghouse plant, the wooden box in which the motor had been placed, hit an overpass while in transport and the box was destroyed. According to the Westinghouse report to the licensee, the bag encompassing the motor remained intact and the motor had not been damaged. Westinghouse also stated that radiological surveys did not indicate any contamination external to the containment bag. All of the material associated with the wooden box was collected and returned to the Westinghouse plant. The state of Pennsylvannia was notified by the licensee.

On December 27, the Unit 1 operators noted a step change in the level of vibration associated with the recently repaired Unit 1 "B" RCP. Containment entries were conducted to verify the control room instrumentation accuracy. Hand-held vibration monitors were used and the results verified the increase in vibration. The present readings of approximately 2.5 mils seismic and 14 mils proximity are just below the alarm set points of 3.0 mils seismic and 15 mils proximity and the required RCP trip setpoints of 5.0 mils seismic and 20 mils proximity. The vibrations appear to have stabilized and no further increases have been noted.

On December 28, at approximately 2200 hours, the licensee discovered that the Unit 1 containment equipment hatch escape air lock was not fully sealed. The discovery was made by a HP technician while performing a routine weekly radiation survey of the containment equipment hatch. The technician heard the sound of rushing air coming from the area of the hatch and informed the control room. Operators were dispatched to the equipment hatch area and discovered that the outer door of the equipment hatch escape air lock was leaking. The operations staff, after notifying station management and discussing the situation with the safety committee, prepared to leak test the air lock to quantify the leak rate in order to verify compliance with TS. Prior to the test, at approximately 0020 hours, the operators discovered that the inner door did not appear to be fully closed as indicated by the hand wheel located just next to the outer door. The operators fully shut the inner door by turning the handwheel approximately 2 turns in the closed direction. Containment integrity was re-established with this action. The leak test of the outer door was then attempted, but failed due to the inability to pressurize the seals. Based on discussions with licensee management, the next step performed by the operators was to open the outer door, wipe down and clean the seals, then re-shut and test the outer door. The outer door seals were found to have rolled from 12 to the one o'clock position, which was causing the leakage. The seals were repaired, cleaned, the door reclosed and tested satisfactorily. The outer door was then opened to allow testing of the inner door, this test was also satisfactory. Finally, the outer door was reclosed and again tested satisfactorily. At this time, 0315 hours on December 29, the licensee exited the TS action statement.

The licensee made an initial determination that additional information concerning the amount of leakage was needed to determine reportability. However, reportability was not reconsidered following the discovery of the inner door not being fully closed until the safety committee met to discuss the problem at approximately 0700 hours on December 29, at which time the committee determined the event to be a four report per 10 CFR 50.72. At approximately 1040 hours, following a hypothesised calculation of the leakage rate by station engineering based on an assumed-sized leakage path, the licensee determined the event to be a one hour reportable per 10 CFR 50.72 and made the report to the NRC. The inspectors had been notified of the occurrence early the morning of December 29 (approximately 0630 hours). Following the notification, the inspectors reviewed the event and determined that both the air lock doors and their seals had been tested satisfactorily per 1-PT-61.2.3, Containment Type B Test-Equipment Hatch, on December 17, 1989. This test was conducted following the containment closeout associated with the completion of a short outage on Unit 1 which began on December 5, 1989. There was no other documented testing or operation of the equipment hatch or the escape air lock since the test was performed on December 17. The licensee had completed testing of the air lock earlier on December 12, but due to the developement of an electrical ground on the "B" RCP motor requiring replacement of the motor, the outage was extended and the equipment hatch had to be removed again. This was the reason for the additional air lock testing on December 17. On December 24, security officers conducted an alarm test on the security door located just outside the equipment hatch. The officers, during an interview conducted by the licensee, stated that they did not notice any air inleakage noise or any other abnormal conditions at the time of their alarm test. This provided some indication that the leakage was not occuring prior to December 24, but is not conclusive. The licensee is continuing an investigation in an attempt to determine who or what caused the inner door to not be fully closed and the cause of the outer door leakage. The inspector noted that the handwheels to the outer and inner doors of the escape air lock are only accessible, with the Unit at power, by using both a security key and a high radiation HP key on the security door installed in the shield blocks located just outside the equipment hatch.

Since the engineering calculation determined that the leakage rate exceeded the TS allowable leakage, the licensee appears to be in violation of TS 3.6.1.1 for loss of containment integrity. This item will be identified as apparent violation 338/89-35-01. Also, the time from the event until the decision to make a four-hour report, appears excessive and in violation of the reporting requirements of 10 CFR 50.72. This item will be identified as apparent violation 338/89-35-02.

On December 20, 1989, the inspector attended containment access training which together with respirator training is a requirement for containment entry. The inspector noted that administrative procedure 20.9, Containment Entry and Exit Under Subatmospheric Containment, allows a minimum of two personnel in the containment. The procedure also requires that a minimum of two personnel be required to move a victim. These two requirements would necessitate getting help from outside of the containment. Step 8.1.1.2 of the procedure, requires first aid be administered if deemed prudent. Also, Step 8.1.1, states that, "Upon being notified of a personnel injury in containment, the predesignated emergency team shall be immediately prepared to enter containment." The inspector determined that the licensee does not require that the emergency team be first aid qualified or in anti-contamination clothing and available for immediate entry into containment.

The inspector believes that the implementation of the procedure is weak in the area of personnel safety by failing to require an emergency team that is first aid qualified and immediately prepared to enter the containment. The licensee maintained that in the event of an accident in the containment, they could respond within five minutes and do not consider this any different from any other accident. The inspector could find no abnormal procedures that addressed a quick entry into the containment and received different responses from shift personnel on the action that would be taken in an emergency. The inspectors will continue to monitor licensee actions associated with containment entries at power.

On January 2, at 0602 hours, the control room operators tagged out the Unit 1 "A" LHSI pump, 1-SI-P-1A, to support corrective maintenance on the pump. The maintenance consisted of the repair of a leaking vent plug installed on the pump seal cooling system and the repair of a leaking discharge relief valve. The leak on the vent plug was not repaired because the plug was galled and the mechanics were unable to remove the plug. A pre-work inspection of the job would have identified the galled plug and appropriate actions could have been planned to repair the plug. The leaking relief valve was not immediately repaired because the mechanics did not have the parts necessary to perform the repair. Also, when the parts became available late on second shift, the mechanic discovered that a support was obstructing the work area. The removal of this support would have required an engineering evaluation to be performed. At this point, station management decided to stop the maintenance activities and have operations untag the pump and declare it operable. This action was completed with the Unit 1 "A" LHSI pump being declared operable at 1007 hours on January 2. Because the licensee not only failed to properly plan scheduled maintenance on a LHSI train and did not even observe the job site to review the work to be performed or verify that the parts were available, a piece of important safety-related, TS required equipment was taken out of service for approximately 16 hours without any maintenance being performed. The pump was returned to an operable status prior to exceeding any TS action statements and the licensee informed the inspector that actions would be taken to prevent recurrence of the problem. The inspectors consider this lack of planning to be a weakness and will continue to monitor the licensee's actions associated with maintenance being performed on safety-related equipment.

The licensee is continuing to experience problems with the instrument air system. On several occasions the operators have discovered service air to instrument air backup isolation valves (1-SA-PCV-105 and 1-SA-PCV-205) open, even though instrument air pressure is above the low pressure setpoint. These valves are supposed to open when instrument air pressure drops below approximately 92 psig, to maintain the instrument air pressure. The problem with the operation of these valves is that service air is supplied by the construction air compressors, which are not oil free and supply air that contains considerable amounts of moisture. The original oil free service air compressors, which were installed in the auxiliary building, have been removed because the licensee was unable to maintain them operable.

The installation of the new instrument air and service air compressors has been delayed beyond the original committment date of December 31, 1989. The NRC is presently reviewing a letter from the licensee dated December 21, 1989 discussing the reasons for the delays and the suggested new schedule for completion. One impact resulting from the delay concerns the repair of the original instrument air compressors. Because of numerous problems and the fact that the new instrument air compressors were to be installed in December 1989, the licensee decided that it was impractical to maintain the original compressors fully operable. These compressors are the only compressors which are powered from the emergency bus and therefore designed to supply air during a loss of offsite power event. Consequently, until the new instrument air compressors are installed the only reliable source of air, which does not rely on offsite power is the temporary diesel powered air compressor located just outside of the turbine building.

The presently installed desiccant dryer located in the turbine building has continued to cause the plugging of the post filter due to carryover of desiccant particles. This requires the dryer to be taken out of service to allow replacement of the post filter approximately every seven days and the refrigerant dryer used in its place. The refrigerant dryer has exhibited faulty operation in the past and has a history of needing to be charged to try to maintain a low enough dew point.

The licensee maintains that even with the above problems the quality of air is being maintained acceptable and is sampled on a routine basis to verify the acceptability. Air samples have been taken by an outside vendor and the inspector will review the test results on air quality when they are received by the licensee. The inspector will also continue to monitor the licensee's progress regarding the instrument and service air system upgrades.

No violations or deviations were identified.

7. Operating Reactor Events (93702)

The inspectors reviewed activities associated with the below listed reactor events. The review included determination of cause, safety significance, performance of personnel and systems, and corrective action. The inspectors examined instrument recordings, computer printouts, operations journal entries, scram reports and had discussions with operations, maintenance and engineering support personnel as appropriate.

On December 5, 1989 at 2236 hours, Unit 1 experienced an automatic reactor trip due to low-low level in the "B" SG. The unit was operating at seven percent power at the time following several power reductions due to EHC oil pressure and turbine control valve problems. Several months ago, as discussed in NRC Inspection Report 338,339/89-31, the licensee began experiencing EHC oil pressure problems. To compensate, the licensee had both EHC pumps operating to maintain pressure above 1700 psig. Normally only one pump operating intermittently was required to maintain pressure greater than 2000 psig. Also, the licensee had experienced several load rejects due to the EHC problems prior to the reactor trip.

On December 5, power was being reduced due to a series of EHC pressure transients and to perform maintenance on the EHC system in an attempt to correct the pressure problems. At 1814 hours, the unit experienced a 100 MW load reduction due to governor valve erratic operation and reactor power was reduced to 30 percent in an attempt to stabilize the unit. The

EHC control continued to be erratic and another EHC pressure transient resulted in governor valve operation which stabilized the unit at approximately seven percent power. At this point the turbine was manually tripped due to increasing SG levels. These increasing levels were a result of the level swell due to the unit transient and the steam dumps coming open. Shortly afterwards, the "C" SG exceeded the high-high level setpoint isolating normal feedwater. Auxiliary feedwater started, but was secured due to continued increases in the SG level. Approximately 6 minutes later, SG levels started to decrease and consequently auxiliary feedwater was unisolated and attempts were made to unisolate and restore main feedwater to stop the level decrease. Even though main feedwater was restored, the "B" SG level continued to decrease to the low low setpoint and the reactor automatically tripped.

The operators handled the trip satisfactorily and no major problems occurred with equipment following the trip. All safety-related systems and components operated as required with the exception of the source range instruments. Because of previous known problems, neither of the source range instruments were operable and the licensee had to proceed to cold shutdown to repair the source range instruments, EHC system and various other problems with the unit.

As discussed previously, the EHC system began to degrade several months prior to the trip. Also, because of an equipment malfunction, the source range instruments had been inadvertently energized during power operations several months earlier resulting in their inoperability. Since these instruments were declared inoperable, the licensee indicated that they would attempt to maintain unit power above five percent, and if the unit power was allowed to drop below five percent (e.g. Mode 2) then the unit would have to be taken to cold shutdown to make source range instruments operable as required by TS. Although no regulatory requirements were violated, the decision to continue operation with a degraded EHC system and maintain power above five percent contributed to the automatic trip of the unit.

Following the reactor trip on December 5 and the subsequent electrical ground which developed on the "B" RCP motor December 12, the licensee conducted a Unit 1 reactor startup during the evening of December 20. Just prior to the restart, the licensee conducted two evolutions considered by the inspector to be strengths. The first involved a startup assessment which consisted of an evaluation conducted by each department to ensure that within their area of responsibility, all equipment, components, paperwork etc. necessary to support the unit restart had been completed or properly evaluated. This evaluation was then presented to station management for their review, questions, comments, and subsequent approval. This restart assessment not only provided station management with objective evidence that the unit was ready for restart, but also demonstrated management's desire to take the time and effort necessary to ensure the unit restart decision has been properly evaluated, even for relatively short duration outages. The second evolution involved reactor startup training on the simulator for all the licensed operator shift groups which were involved in the restart. The inspectors attended a portion of the training sessions on December 19. The training session not only allowed the operators to re-familiarize themselves with the normal startup procedures by starting up a unit, using the simulator, but it also included a presentation regarding industry events that had occurred during previous reactor startups.

The Unit 1 startup commenced at 2200 hours on December 20. The inspector witnessed the startup from the control room and reviewed portions of the following procedures:

a. 1-OP-1C, Estimated Critical Position
b. 1-OP-1.5, Unit Start from Mode 3 to Mode 2
c. 1-OP-2.1, Unit Startup from Mode 2 to Mode 1

The ECP calculated by 1-OP-1C was determined to be 165 steps on "D" control rod bank with an acceptable range of 89 - 211 steps. The unit was actually declared critical by the operators at 2255 hours on December 20 at step 178 on "D" control rod bank and then stabilized by procedure and verified just critical at 2302 hours, step 172 on "D" bank. This was well within the acceptable range established by the ECP procedure 1-OP-1C as discussed above. The unit entered Mode 1 at 0347 hours on December 21 and the generator was placed on line at 0434 hours. The startup was observed by the inspector to have been deliberate, controlled and well performed. The inspector did not identify any problems related to the startup.

On December 20, the inspector reviewed an internal licensee memorandum from corporate engineering to the station addressing the channel check criteria for the steam and feed flow instrumentation during startup when reactor power is below 20 percent. The memorandum was a result of a request from the Senior Vice President - Nuclear, to corporate engineering to provide justification for a greater channel check tolerance during startup and low power operations and had just been received by the station and not reviewed. The conclusion of the memorandum was that channel checks were not applicable at power levels below 20 percent power and therefore need not be performed. Following station management review, the inspector was informed that the recommendation was considered to be inadequate and the startup would be conducted using the current channel check criteria. Station engineering had not reviewed the basis for the memorandum.

The purpose of the request from the station was to establish an engineering basis for a wide enough tolerance in the channel check criteria to verify operability of the instrumentation during periods of low power operation, but not place the instruments in the trip condition unnecessarily. The instrumentation is not as accurate at low power operation (less than 20% power) and may be placed in a trip condition due to the channel check tolerance even though the instrument is fully operable. The inspector agrees with the station's desire to reach an optimum channel check tolerance but considers the recommendations of corporate engineering to indicate a lack of understanding of both the regulatory requir ments and the basis for the operability verification of RPS and SI instrumentation. The recommendation not only ignored the TS requirement to perform a channel check below 20% power, but also ignored the intention for the channel check, which is to provide some objective evidence that the RPS and SI initiation instrumentation is operable. This ensures that the instruments will perform their safety function even if the accident occurs at power levels below 20%. The inspector believes that the above sequence of events demonstrates a weakness in the engineering organization.

No violations or deviations were identified.

8. Licensee Event Report Review (92700)

The following LERs were reviewed and closed. The inspector verified that reporting requirements had been met, that causes had been identified, that corrective actions appeared appropriate, that generic applicability had been considered, and that the LER forms were complete. Additionally, the inspectors confirmed that no unreviewed safety questions were involved and that violations of regulations or TS conditions had been identified.

(Closed) LER 339/87-15, Inoperable Redudant S/G Steam Flow Channel Exceeds Technical Specification Action Statement. The inspector reviewed the licensee's corrective actions for the event, associated EWRs and the results of the licensee's cause investigation of the reversed wiring. The corrective actions taken for the event should preclude recurrence. The root cause of the signal leads reversed polarity from the "A" SG Steam flow channel III wiring was found to be human error made by the installers and the independent verification made by the licensee's quality control organization. The signal leads were reversed at containment penetration 18E-2. Limited access due to supports, in addition to poor lighting in the area of the penetration, were contributing factors to the event. The licensee issued LER 339/87-15-01, dated February 3, 1988, which enhanced the event details and corrective actions reported in the initial LER.

(Closed) LER 338/89-06, Inadvertent ESF Actuation - 1H Emergency Diesel Generator Start. The cause of the event was determined to be personnel error in performance of 1-PT-82.3A, 1H Diesel Generator Test. The inspector reviewed the LER closeout package and verified that the appropriate EDG procedures to prevent testing when in an abnormal electrical configuration had been completed.

(Closed) LER 338/87-20, Reactor Trip generated from 5A Feedwater Heater Hi-Hi Level Signal. The cause of the event was a level switch failure due to fatigue failure of a spring inside the switch microswitch. The licensee replaced the failed unit and inspected all other feedwater heater level switches which initiate reactor trips. No other problems were identified. Because of this event, the licensee evaluated the installation of additional level switches for the hi-hi level trip signal so that a single failure would not result in a turbine/reactor trip. No problems were identified by the engineering evaluation and subsequently the modification was performed via EWRs 88-148 and 88-149. The modification wired a spare level switch contact in series with the existing contact for input to the turbine trip logic and should reduce the probability of false trips while preserving secondary plant protection. The inspector reviewed the LER, associated corrective action items, and level switch modification EWR's.

(Closed) LER 338,339/88-25, Inoperable Recirculation Spray Subsystem. The cause of the event was a loss of administrative control in verifying that at least one train of the recirculation spray subsystem was operable prior to removing the redundant train from service. The inspector reviewed the LER closeout package. Revisions were made to Administrative Procedure 16.7 in order to better coordinate ongoing testing activities and improve the interface between the Shift Supervisor (outside the control room) and the applicable Unit SROs in the Control Room. The inspector also reviewed a memorandum to the operations personnel dated February 6, 1989 regarding implementation of the Work Request Program. This correspondence highlighted many aspects of the program and included the identification of deficiencies, redundant work requests, and Shift Supervisor authorization and knowledge of ongoing maintenance or testing. The inspector considers the corrective actions taken are adequate to prevent recurrence of the event.

(Closed) LER 338/88-12, Loss of RHR Capability Due to Failed Solenoid Operated Valve. The cause of this event was the failure of containment isolation valve 1-CC-TV-103B, to stroke closed within the required time limit, compounded by the lack of spare parts to repair the failed SOV. Initial corrective actions included replacement of the SOV from 1-CC-TV-103A to 1-CC-TV-103B in order return one RHR subsystem to operable status. Subsequently, the SOV from 1-CC-TV-103B was refurbished and installed on 1-CC-TV-103A. Both valves were satisfactorily stroked after installation. Replacement SOVs and repair kits, had been on order with the manufacturer for several months prior to the event. The inspector reviewed the LER closeout package.

(Closed) LER 338/88-08, Inadvertent PORV Actuation During Solid Water Operations. The inspector reviewed the LER closeout package which included revision 1 of LER 88-08. Each of the corrective actions addressed was reviewed and found to be acceptable. The corrective actions for the event were taken into account for both Unit 1 and 2. The licensee evaluated the possibility of changing the station's heatup and cooldown curves. After reviewing the results of this study, a TS change was submitted and approved for Unit 1 (TS Amendment 117) to adjust the low temperature overpressure setpoint in order to provide a wider band for mode 5 operations at less than or equal to 200 degrees F. A proposed TS change for Unit 2 will be submitted pending the licensee's findings regarding heatup and cooldowns curves for Unit 2. The inspector considers this LER closed.

(Closed) LER 338,339/88-18, Missed Surveillance - Post Accident Containment Pressure Transmitters. The cause of the missed surveillances was attributed to the failure to recognize that the modification that installed the containment wide range pressure transmitters was implemented to meet the requirements of TS 3.3.3.6 for wide range post accident pressure instrumentation. During the design changes in May 1981 for Unit 1 and July 1981 for Unit 2, personnel did not conclude that a new procedure was required to perform the TS required channel check or channel calibration. The licensee entered and cleared the Action Statements of TS 3.3.3.6 by the completion of the transmitter replacement and the performance of the TS required channel check. In addition, the CR operator logs have been permanently revised to perform channel checks one per 8 hour shift. The inspector reviewed the LER closeout package and considers the corrective action taken appropriate.

(Closed) LER 338, 339/89-13, Incore Flux Mapping Frame Assembly Discount to be Unrestrained. As a result of the event, the Unit 1 and Unit 2 incore flux mapping frame assemblies were seismically mounted on July 7, 1989 and July 6, 1989, respectively. The cause of the event was inadequate installation in accordance with the vendor technical manual. The licensee completed a 10 CFR 50.59 Safety Evaluation prior to performing the addition of the seismic restraints to the frame assemblies. The inspector reviewed the LER closeout package and associated EWR.

(Closed) LER 338/88-20, Reactor Trip on SF/FF Mismatch Coincident with "A" Low Level Due to MFRV closure. The event involved an automatic reactor trip from 100 percent power. The "B" main feedwater regulating valve failed closed due to a degraded voltage condition because the "A" RSST tap change motor breaker tripped on over current after the shunt reactor was placed in service. Corrective actions included replacement and testing of the "A" RSST tap changer motor and control relays. The event did not produce a transient beyond the normal capability of the feedwater regulating valves to control. After the event, the "B" main feedwater regulating valve stem was found broken at the actuator coupling. Subsequently, the valve stems on all three main feedwater regulating valves were replaced, and the valves were satisfactorily cycled. The licensee also has fitted Unit 1 with feedwater regulating valve trims with those that were previously installed on Unit 2. The new trims should greatly reduce in-service vibrations which lead to stem and other mechanical failures of the feedwater regulating valve. The inspector reviewed the LER and the completion of the corrective actions.

(Closed) LER 338,339/88-24, Service Water Flow Not Within USFAR Assumptions. The event involved the determination of October 13, 1988 that there may be insufficient SW flow available to the RSHX's in the event of a DBA. The potential for this was due to having only two SW pumps in operation, with two CCHX's in operation for the unaffected unit, instead of only one CCHX per unit as assumed in the UFSAR. Operating in this configuration during a DBA could result in either reduced flow to the RSHX's or possibly cause damage to the SW pumps due to run out. On October 14, 1988, the licensee issued Standing Order Number 165, which required one SW pump through one CCHX be maintained operable or limit flow through two CCHX's to ≤ 9,600 gpm on the SW side. On February 17, 1989, this standing order was revised (Rev. 1) to add restrictions on the total SW flow rates. The licensee then performed a flow test on the SW system and discovered that both units had insufficient flow to at least one RSHX. The SW MOV's that throttle flow to the RSHX's were found not set in accordance with the setpoint documentation. All deficiencies were corrected. Subsequent to the results of the SW flow test, in order to ensure adequate SW operations, the licensee again revised Standing Order Number 165 (Rev. 2) to require the maintenance of a least three SW pumps at the reservoir operable during a DBA as well as requiring other preventative measures to assure proper SW flow. The inspector reviewed the LER closeout package and corrective actions taken for the event.

(Closed) LER 339/88-03, Inadvertent ESF Activation During Maintenance. All other motor operated valves with similar interlocks have been identified. Procedures were revised to give cautions and require the use of insulated tools.

(Closed) LER 338/89-17, Reactor Trip Resulting from EHC System Transient. During the outage following the reactor trip, the licensee performed the necessary corrective maintenance on the EHC system to correct the problem which contributed to the reactor trip and prevented the EHC system pressure from being stable.

9. Action on Previous Inspection Items (92701, 92702)

(Closed) TI 2515/104, Initial Licensee Fitness For Duty Training. The inspector observed portions of the FFD training activities conducted by the licensee's training organization on December 4 and 7, 1989. The areas for evaluation included policy awareness training, FFD training for supervisors, and FFD escort training. The licensee's training consisted of a general FFD training for all non-supervisory personnel and a separate FFD training for site supervisors, both of which were presented at various times prior to January 1990.

The areas of the FFD training program which were evaluated included the following:

FFD program requirements and objectives.
Individual and group responsibilities.

Policies concerning use, sale or possession of illegal drugs.
Possession of illegal drugs.
Policy on abuse of selected drugs and alcohol.
Indicators of mental stress, fatigue and illness
Policy for employee refusal of drug testing.
Type drug testing including those requiring testing.
Licensee sanctions for drug and alcohol abuse.
Behavioral observation techniques for recognizing effects of chronic alcohol and drug use.
Methods for reporting FFD concern to supervision and security.
Policies and procedures which govern confronting an employee, removing and employee, referral of an employee to employee assistant program, and the basis for initial and for cause testing.
Identification of chemical and street names of selected drugs.
Employee Assistance Program.

The inspector considers that the training sessions adequately presented the scope and consequences of the FFD rule as defined by 10 CFR 26. All individuals attending either training were required to pass a short examination or repeat the training until the exam results were satisfactory. During the observed training sessions all individuals passed the exam.

(Closed) Unresolved Item 338,339/87-36-01, Potential Flooding of Safety-Related Equipment. The licensee has built a dirt wall on the west side of Unit 2 turbine building to prevent flooding of the turbine building during a worse case flooding situation.

(Closed) Violation 338/87-24-06, Failure to Notify Health Physics When a Rad Monitor Alarm was Received. The inspector verified that the licensee has completed eight action items as a result of a response to this violation. The actions included further training and revision of emergency procedures, alarm response procedures and standing orders.

(Closed) Unresolved Item 338,339/87-10-01, Verify Operability of RWST Level Probes. The licensee developed a procedure to test the level probes. The licensee also submitted and received a TS change which adjusted the allowable RWST level range to that which could be accurately indicated and monitored by the control room level instrumentation.

(Closed) Unresolved Item 338,339/88-27-03, Loss of Configuration Control. A valve checkoff of the primary grade water system outside containment was performed using 1-OP-9A. The valve checkoff ensured the primary grade system was in the proper configuration. This item was reclassified as a violation and closed in NRC Inspection Report 338,339/88-31-02, however due to an oversite, was listed as 338,339/88-27-02.

10. Exit

The inspection scope and findings were summarized on January 3, 1990 with those persons indicated in paragraph 1. The inspectors described the areas inspected and discussed in detail the inspection results listed below. The licensee did not identify as proprietary any of the material provided to or reviewed by the inspectors during this inspection.

Item Number	Description and Reference
338/89-35-01	Apparent violation of TS 3.6.1.1 for loss of containment integrity (paragraph 6).
338/89-35-02	Apparent violation concerning the timeliness of a decision to make a four-hour report to the NRC (paragraph 6).

A weakness was identified with regards to a lack of planning associated with maintenance being performed on safety-related equipment (paragraph 6).

A weakness was identified concerning procedure implementation of personnel safety requirements as related to emergency team response inside the containment (paragraph 6).

A weakness was identified concerning the corporate engineering's recommendations addressing the channel check criteria for the steam and feed flow instrumentation during startup when reactor power is below 20 percent (paragraph 7).

A strength was noted regarding the licensee's startup assessment in support of unit restart following a trip (paragraph 7).

A strength was noted whereby the licensee conducted startup training on the simulator for all licensed operator shift groups involved in unit restart (paragraph 7).

11. Acronyms and Initialisms

AP	Abnormal Procedure
AUX	Auxiliary
CAD	Computer Assisted Drawing
CAE	Condenser Air Ejector
CCHX	Component Cooling Water Heat Exchanger
CDA	Containment Depressurization Actuation
CRO	Control Room Operator
DBA	Design Bases Accident
DCP	Design Change Package
DHR	Decay Heat Removal

DUR	Drawing Update Request
ECP	Estimated Critical Position
EDG	Emergency Diesel Generator
EP	Emergency Procedure
EHC	Electro-hydraulic Control
ESF	Engineered Safety Feature
EWR	Engineering Work Requests
F	Fahrenheit
GPM	Gallons Per Minute
HP	Health Physics
IFI	Inspector Follow-up Item
LCO	Limiting Condition for Operation
LER	Licensee Event Report
LHSI	Low Head Safety Injection
MCC	Motor Control Center
MFRV	Main Feedwater Regulator Valve
MOV	Motor Operated Valve
MPC	Maximum Permissible Concentration
MREM	Millirem
MSSV	Main Steam Safety Valve
MW	Megawatt
NRC	Nuclear Regulatory Commission
NSE	Nuclear Safety Engineering
PDTT	Primary Drain Transfer Tank
PES	Plant Engineering Services
PORV	Power Operated Relief Valve
PROM	Programmable Read Only Memory
PSIG	Pounds Per Square Inch Gauge
PTSS	Periodic Test Scheduling System
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RHR	Residual Heat Removal
RMS	Radiation Monitoring System
RPS	Reactor Protection System
RSHX	Recirculation Spray Heat Exchanger
RSST	Reserve Service Station Transformer
RTD	Resistance Temperature Detector
RWP	Radiation Work Permit
RWST	Refueling Water Storage Tank
SG	Steam Generator
SALP	Systematic Assessment of Licensee Performance
SF/FF	Steam Flow/Feed Flow
SI	Safety Injection
SNSOC	Station Nuclear Safety and Operating Committee
SOV	Solenoid Operated Valve
STA	Shift Technical Advisor
SW	Service Water

TAVE	Average Temperature of the RCS
TS	Technical Specification
TSC	Technical Support Center
UE	Unusual Event
URI	Unresolved Item
UFSAR	Updated Final Safety Analysis Report
VCT	Volume Control Tank
WOG	Westinghouse Owners Group