UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W., SUITE 2900
ATLANTA, GEORGIA 30323

Report Nos.: 50-280/92-17 and 50-281/92-17

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

Docket Nos.: 50-280 and 50-281

License Nos.: DPR-32 and DPR-37

Facility Name: Surry 1 and 2

Inspection Conducted: July 5, through August 8, 1992

Inspectors:

M. W. Branch, Senior Resident Inspector — Date Signed 9-3-92

J. W. York, Resident Inspector — Date Signed 9-3-92

S. G. Tingen, Resident Inspector — Date Signed 9-3-92

Approved by: P. E. Fredrickson, Section Chief, Division of Reactor Projects — Date Signed 9/3/92

SUMMARY

Scope:

This routine resident inspection was conducted on site in the areas of operations, maintenance, quality verification, and licensee event review. During the performance of this inspection, the resident inspectors conducted review of the licensee's backshifts or weekend operations on July 9, 10, 12, 14, 16, 17, 18, 24, 28, 29, 30, and 31, and on August 5.

Results:
In the safety assessment/quality verification area, the following items were noted:

- The licensee's corrective action in response to Information Notice 88-23, concerning air or gas in emergency core cooling systems, was reasonable (paragraph 3.b).

- The Safety Evaluation and Justification for Continued Operation for operating Unit 2 with the condition of pressure spikes from gas voids in the low head safety injection system (LHSI) system was adequate and the licensee was aggressively pursuing this issue (paragraph 5.a).

- An Inspector Followup Item was identified to evaluate the licensee's long-term plans to correct the gas intrusion problem with the LHSI system (paragraph 5.b)

- Corrective action for deviation reports documenting a problem associated with maintaining control room envelope pressure did not prevent a recurrence of a similar problem and also resulted in an inappropriate procedure change (paragraph 5.b).

- An operational event at another station was evaluated by the corporate operating experience review program personnel and was an example of a timely and thorough review of operating experience (paragraph 5.c).

REPORT DETAILS

1. Persons Contacted

Licensee Employees

*W. Benthall, Supervisor, Licensing
*R. Bilyeu, Licensing Engineer
H. Blake, Superintendent of Site Services
R. Blount, Superintendent of Engineering
*M. Bowling, Manager, Corporate Nuclear Licensing
*D. Christian, Assistant Station Manager
*J. Downs, Superintendent of Outage and Planning
*D. Erickson, Superintendent of Radiation Protection
*A. Fletcher, Assistant Superintendent of Engineering
*R. Gwaltney, Superintendent of Maintenance
*L. Hartz, Manager, Corporate Nuclear Quality Assurance
*M. Kansler, Station Manager
*J. McCarthy, Superintendent of Operations
*A. Price, Assistant Station Manager
*R. Saunders, Assistant Vice President, Nuclear Operations
*E. Smith, Site Quality Assurance Manager
*B. Stanley, Supervisor, Station Procedures

NRC Personnel

M. Branch, Senior Resident Inspector
*S. Tingen, Resident Inspector
J. York, Resident Inspector

*Attended Exit Interview

Other licensee employees contacted included control room operators, shift technical advisors, shift supervisors and other plant personnel.

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

2. Plant Status

Unit 1 began the reporting period in power operation. The unit was at power at the end of the inspection period, day 94 of continuous operation.

Unit 2 began the reporting period in power operation with a leaking pressurizer safety valve. The unit was shutdown on July 6, to repair the leaking safety valve. The unit was returned to power on July 18, after a 13 day outage. The unit was at power at the end of the inspection period, day 21 of continuous operation.

3. Operational Safety Verification (71707, 42700)

The inspectors conducted frequent tours of the control room to verify proper staffing, operator attentiveness and adherence to approved procedures. The inspectors attended plant status meetings and reviewed operator logs on a daily basis to verify operations safety and compliance with TSs and to maintain awareness of the overall operation of the facility. Instrumentation and ECCS lineups were periodically reviewed from control room indication to assess operability. Frequent plant tours were conducted to observe equipment status, fire protection programs, radiological work practices, plant security programs and housekeeping. Deviation reports were reviewed to assure that potential safety concerns were properly addressed and reported.

a. Licensee 10 CFR 50.72 Reports

On July 11, the licensee made a 10 CFR 50.72 report concerning the accumulation of gas in the piping between the Unit 2 LHSI and HHSI pumps. During the recirculation mode of operation, the LHSI pumps align to take a suction from the containment sump and discharge to the HHSI pumps. The licensee's initial evaluation of the gas pockets indicated the quantity of gas found in the piping could have resulted in gas binding of the HHSI pumps and disabled the pumps during the recirculation mode of operation. On July 28, the licensee withdrew the 10 CFR 50.72 report based on a Westinghouse evaluation that the HHSI pumps were operable. This issue is further discussed in paragraph 3.b.

On July 13, the licensee made a 10 CFR 50.72 report concerning inoperable LEOF HEPA filters for a duration greater than one hour. A lawn care crew truck bumped a nonsafety related transformer at the training center and partially knocked the transformer off its pedestal. While trying to place the transformer back on its pedestal, smoke issued from the transformer. When removing the transformer from service, power to the LEOF had to be deenergized which rendered the HEPA filters out of service.

On July 14, the licensee made a 10 CFR 50.72 report concerning an ESF actuation in Unit 2. Unit 2 AFW MOVs, 2-FW-MOV-251A through F, opened automatically as a result of circuitry interlock signals that initiated AFW flow when both MFW pumps trip. The unit was at CSD and AFW was not initiated because the pumps' control switches were in the pull-to-lock position. The event occurred when operators deenergized the A station service bus in order to deenergize a non-safety chiller that could not be secured locally. The running condensate pump, which was powered from the A station service bus, tripped and caused a low MFW pump suction pressure signal. The control circuitry then initiated a trip signal to MFW pumps and an AFW initiation signal. No other ESF actuations occurred. This event is further discussed in paragraph 3.c.

On July 27, the licensee made a 10 CFR 50.72 report concerning invalid indication for several parameters in the Unit 1 safety parameters display system. The event occurred at 6:00 p.m. during an electrical storm and the system was returned to service at 8:05 p.m. The cause of the invalid indication was determined to be Group RC1-1, Unit 1 reactor coolant pumps, not being scanned.

b. Voids In LHSI System Piping

Both Unit 1 and 2 have two LHSI pumps which are normally aligned to take suction from the RWST and discharge to each RCS loop cold leg. In this alignment, two check valves in series are located in each of the three LHSI pump discharge lines to the RCS cold legs. These check valves are the boundary between the high pressure RCS and low pressure LHSI systems. On a low level signal from the RWST, the LHSI pumps automatically realign to take a suction from the containment sump and discharge to the CH\HHSI pumps via the RMT piping. During RMT, the LHSI pumps continue to also discharge to the RCS cold legs.

Recent testing of the Unit 2 LHSI pumps identified the occurrence of short duration pressure spikes in low pressure LHSI piping when starting a pump. LHSI pressure spikes are further discussed in paragraph 5.a. When investigating these pressure spikes, the licensee discovered gas voids in the LHSI pump discharge piping. Approximately 50 cubic feet of gas was vented from vent valves 2-SI-445 and 2-SI-192 in the LHSI pump discharge RMT piping. Another 32.5 cubic feet of gas was vented from vent valves 2-SI-193 and 2-SI-179 in the LHSI pump discharge to the RCS cold leg piping. The licensee then began to routinely vent the piping and over the next week approximately 26 cubic feet of gas was vented from the LHSI pump discharge to the RCS cold leg piping. At the end of the inspection period, the licensee was routinely venting this piping and small amounts of gas continued to appear at 2-SI-179. All samples of the vented gas were analyzed and were found contaminated and had a mixture of hydrogen, oxygen, and nitrogen; however, the concentrations of hydrogen, oxygen and nitrogen in the samples were inconsistent. Some of the samples indicated a very high concentration of nitrogen, and the licensee is continuing to investigate the source of this gas. Other gas samples contained high concentrations of hydrogen.

Gas voids were also identified in the Unit 1 LHSI piping. Approximately four cubic feet of gas was vented from valves 1-SI-192 and 1-SI-197 in the RMT piping between the LHSI and CH\HHSI pumps and 30 cubic feet of gas vented from valves 1-SI-198 and 1-SI-179 in the LHSI pump discharge to RCS cold leg piping. At the end of the inspection period, the licensee was routinely venting this piping and occasionally a mixture of gas bubbles and water would appear at 1-SI-179.

It appears that the source of gases may be from the leakage of reactor coolant past the SI cold leg check valves. The LHSI pump discharge piping to the RCS cold legs and to the CH/HHSI suction is vented to the RWST via the LHSI pumps' recirculation line. Once the reactor coolant leaks past the cold leg check valves, the leakage depressurizes to approximately 20 psig and cools down to ambient temperature. The gases in the reactor coolant, during this process, come out of solution and migrate to the high points of the LHSI pumps' discharge piping.

Cold leg check valve back-leakage is particularly evident in Unit 2 in that the unlagged LHSI pump discharge header to the RCS cold legs is hot to the touch, approximately 120 degrees F, and RWST in-leakage up to .3 gpm have been measured. Also, temperature of piping in the containment adjacent to the B and C cold loops check valves is approximately 50 degrees F higher than the A loop cold leg piping. This indicates back-leakage from the B and C cold leg check valves. Based on the absence of the same indicators, cold leg check valve back-leakage in Unit 1 is not evident.

TS 3.1.C.7.a requires that loops A, B, and C cold leg check valves, which also function as pressure isolation valves, be leak rate tested prior to the unit going critical. This TS allows a leakage rate of up to five gpm for each valve. Results of the Unit 2 cold leg check valve seat leakage testing performed in July, 1992, indicated that with the combined back-leakage rate for all three loops was approximately .11 gpm with a 300 psi differential. When normalized to normal operating pressure, the leakage was within TS limits. Results of the Unit 1 cold leg check valve seat leakage testing performed in April, 1992, indicated a .05 gpm combined back-leakage for all three loops. The LHSI system is configured such that cold leg back leakage is directed to the RWST via the LHSI pumps' recirculation lines.

Operability of the CH/HHSI pumps with gas voids in the LHSI RMT piping was evaluated by Westinghouse. The Westinghouse analysis concluded that the pumps were operable with the gas voids present. The gas voids in the LHSI pump to RCS cold leg piping was evaluated by the licensee to have a negligible effect during a loss of coolant accident.

In October 1988, the licensee identified voids at a several locations in the suction of the CH/HHSI pumps. These voids were identified as a result of the licensee's review of NRC Information Notice 88-23, Potential For Gas Binding Of High-Pressure Safety Injection Pumps During a Loss-Of-Coolant Accident, dated May 12, 1988. The licensee installed vent lines and routinely vented piping at CH/HHSI suction areas where the voids were identified. The source of these gas voids were hydrogen from the VCT and air from the RWST. Once the licensee installed vents and routinely vented these locations, measurable amounts of gases were no longer present in the effected areas. The licensee also evaluated

Supplement 3 to Information Notice 88-23, dated December 10, 1990, by considering the potential of air in other ECCS systems. The other systems evaluated were RHR, SW, AFW, and CCW and the licensee concluded that air was not a problem or actions had been previously taken to prevent the accumulation of air. The NRC staff concluded that the licensee's actions in response to Information Notice 88-23 and its supplements were reasonable.

The licensee met with the NRC staff on August 5, 1992, and discussed the identification and evaluation of this problem. Also discussed were the licensee's actions with respect to Information Notice 88-23. Although the licensee's short-term actions of periodically venting the affected piping were satisfactory, the licensee had not yet completed long-term plans to resolve the root cause of the gas intrusion problem. The licensee is being requested to provide these plans to the NRC. Followup of these actions is identified as Inspection Followup Item 280,281/92-17-01, Gas Void Long-Term Corrective Action.

c. Failed SW Supply Line to the 555 Ton Chiller

At approximately 11:20 p.m. on July 13, an operator reported that a large SW leak was noted in the Unit 2 TB in the vicinity of the 2-CD-REF-1 (Unit 2 555 ton non-safety related chiller). The control room initiated AP-13, Turbine Building or #3 MER Flooding, and isolated the leak by turning off the SW supply pump. The leak was from a fitting in an 8 inch mono-strand (i.e. fiberglass) chiller SW supply line, which had separated from the pipe at the joint. The licensee estimates that approximately 1000 gallons of water spilled on the TB floor prior to the leak being isolated. The inspector received notification from the Station Manager at approximately 3:30 a.m. and arrived at the site shortly thereafter to access and follow up on the event.

Based on discussions with plant personnel, the inspectors determined that an area of approximately 2000 square feet of flooring around the Unit 2 chiller was covered with water approximately 2 to 3 inches deep. Some non-safety related equipment was reported to have shorted during the flooding and the licensee indicated that the TS sump pumps performed as expected and removed the water prior to any appreciable accumulation.

Unit 2 was shutdown at the time and Unit 1 was at 100% power when the SW leak occurred. The SW line leak occurred after operators thought they had secured chiller 2-CD-REF-1. Operators deenergized the chiller locally and secured service water flow through the chiller; however, the chiller's supply breaker malfunctioned and did not open when the chiller was secured. A manual valve on the SW discharge side of the chiller was shut to secure SW/chiller flow. With the chiller still operating and the SW flow secured, the temperature of the SW increased causing pressure to increase that resulted in the fitting failure. A

check valve in the chiller's SW supply piping prevents reverse flow through the chiller; however, when the piping failed, the check valve opened and SW spilled into the TB from the failed joint. In order to deenergize the chiller, the A station service bus was deenergized. This also deenergized the operating condensate pump. Tripping of the condensate pump generated a main feed pump trip signal which resulted in an ESF actuation in Unit 2. Unit 2 AFW MOVs, 2-FW-MOV-251A through F, opened automatically as a result of circuitry interlock signals that initiate AFW flow when both MFW pumps received a trip signal. Since Unit 2 was shutdown, AFW was not initiated because the pumps' control switches were in the pull-to-lock position.

The licensee reported the ESF actuation as required by 10 CFR 50.72. However, the SW leakage was not mentioned since it did not meet the licensee threshold for flooding and did not require activation of the emergency plan.

The inspectors reviewed a report from the licensee's materials laboratory where the failed joint was compared with tests on an adjacent unfailed joint. The failed joint fracture occurred through the joint adhesive which had numerous areas of porosity and exhibited approximately 35 percent bond. The unfailed joint was broken in the laboratory and exhibited approximately 85 percent bond with very little porosity present. Sections of each of the two joints were sent to an outside laboratory to determine if the adhesive was properly mixed.

The licensee is conducting a root cause analysis of the above event and the inspectors will followup on this event.

d. Observation of Unit 2 Startup

Following a review of procedure 2-OP-RX-004, Estimated Critical Conditions, dated April 24, 1992, the licensee began to pull Unit 2 control rods to criticality at 6:20 a.m. At 7:40 a.m., with the D bank at 171 steps, the unit was declared critical. The ECP was 100 steps on D bank. The reactor power was then raised to a specific power and according to procedure, the D bank was then reinserted to 171 steps. At this time, it was determined that the reactor was subcritical when it should have been critical. The D bank was then reinserted to 5 steps (as required by procedure) and it was decided to trip the reactor and re-start the procedures after the situation had been properly evaluated. The resident inspector was contacted and arrived at the site to observe the weekend startup and the licensee's assessment of the previous startup attempt.

Surry personnel consulted with the NAF group in Innsbrook to assess the ECP from the first startup. The NAF group had recently completed a study to evaluate North Anna and Surry calculations in order to improve the current ECP methodology. An ECP calculation

was made for the new Surry startup using the new method (new position 137 steps on the D bank). A telephone conference was held with operations, the station manager and other site senior managers to discuss this evaluation with the results being permission to resume the startup of Unit 2.

The inspectors observed the startup briefing and other activities including pulling the rods. The reactor was declared critical at 7:15 p.m. at 180 steps on the D bank. There no further problems with the startup.

Within the areas inspected, no violations were identified

4. Maintenance Inspections (62703) (42700)

During the reporting period, the inspectors reviewed maintenance activities to assure compliance with the appropriate procedures.

The following maintenance activities were reviewed:

a. Repair of Pressurizer Safety Relief Valves-Unit 2

Unit 2 A pressurizer safety valve was leaking by the seat during the last inspection period and into this inspection period. Various attempts were made to minimize this leakage, such as temporary modifications to the ventilation in the pressurizer cubicle and venting of the PRT. On July 5, the safety valve's seat leakage increased. Although the leakage was still well within TS limits, the licensee decided to shut the unit down and repair the valve.

The licensee removed all three Unit 2 safety valves and sent the valves to Wyle Laboratory for examination, repair, and testing. Visual examination showed steam cuts and wear about 340 degrees around the seating surface for the A safety valve. The B safety valve's seat was steam cut for about 90 degrees and evidence of leakage (a discoloration of the seating surface) for 180 degrees around the seating surface. The C valve had indications of leakage extending for about 25 degrees around the seating surface. Representatives from the valve vendor (Crosby) along with licensee maintenance and QA personnel observed the repair of the valves at Wyle Laboratory. Procedures 2-MPT-0424-01, Pressurizer Safety Valve Setpoint Test 2-RC-SV-2551A, 2-MPT-0424-02, Pressurizer Safety Valve Setpoint Test 2-RC-SV-2551B, and 2-MPT-0424-03, Pressurizer Safety Valve Setpoint Test 2-RC-SV-2551C, dated December 12, 1991, were used to test the the valves. The inspectors reviewed the test results and no discrepancies were noted.

Within the areas inspected, no violations were identified.

5. Safety Assessment and Quality Verification (40500)

a. Review of Safety Evaluation for LHSI Pump Spiking

The inspectors reviewed Safety Evaluation 92-162, dated July 17, 1992, and attended the SNSOC meeting on July 15, for approval of the Safety Evaluation. The purpose of the safety evaluation was to address the operability of the LHSI system following the discovery of short duration pressure spikes in the discharge piping shortly after starting a LHSI pump.

The occurrence of short duration pressure spikes when starting a LHSI pump was originally identified at the North Anna Power Station and in March, 1992, the licensee performed testing at Surry on the Unit 2 LHSI pumps, 2-SI-P-1A and 2-SI-P-1B, in order to determine if the same problem existed at Surry. On the initial starts of the pumps, pressure spiking did not occur. Upon each pump start, system pressure increased smoothly to approximately 216 psig and settled out at approximately 180 psig. However, pump 2-SI-P-1B was restarted two additional times and in both instances pressure spikes in excess of 400 psig occurred. The instrumentation utilized during the test was not accurate above 400 psig. Because the results of this testing were so varied, and instrument accuracies were questionable, additional testing would be required.

On July 1, additional testing was performed. When Unit 2 Pump 2-SI-P-1A was started, several pressure spikes occurred that exceeded 400 psig. The pump was operated for 15 minutes and secured. The pump was restarted and a pressure spike of approximately 320 psig occurred.

Based on similar experiences at North Anna, the licensee concluded that the cause of the pressure spikes may be due to a gas or steam voids within the LHSI system. In order to locate a gas or steam void, the licensee performed ultrasonic testing on the Unit 2 SI system piping. This examination revealed that there was a significant amount of gas in the RMT piping between the LHSI and HHSI pumps, as discussed in paragraph 3.b.

UT also revealed small gas voids upstream of B loop cold leg SI check valve 2-SI-242 and loop C cold leg SI check valve 2-SI-243 at the top of the piping, approximately one eighth of an inch wide and approximately nine feet long. The licensee concluded that the most probable cause of these voids was back-leakage through the cold leg check valves that isolate the high pressure RCS from the low pressure LHSI system. Since the unit was shutdown and cooled down when these gas voids were identified, the licensee concluded that this back-leakage may also create steam voids upstream of the check valves when the RCS is at normal operating temperature.

Previous Unit 2 operating experience indicated a RWST level increase of .3 gpm during power operation. Although the exact source of the leakage into the RWST is unknown, the licensee considers that the leakage was from the RCS through the cold leg check valves. The LHSI system is configured such that cold leg check valve back-leakage would discharge to the RWST via the LHSI pump recirculation piping. Based on a .3 gpm check valve leak, the licensee estimated that a 7.5 cubic foot steam bubble could exist during power operation. Using engineering analysis with the aid of a consultant, the licensee determined that a 7.5 cubic foot steam bubble would create an estimated 600 psig pressure spike for a duration of approximately .4 seconds with a maximum instantaneous peak of 700 psig. The magnitude of this pressure spike was attributed to the steam bubble collapse when a LHSI pump was started. Since gas voids would compress rather than collapse like a steam bubble, they are not considered to significantly contribute to the magnitude of the pressure spikes.

The safety evaluation addressed two concerns as a result of pressure spikes in the LHSI system when starting a LHSI pump. The first concern was the potential for exceeding the LHSI system piping design pressure. The safety evaluation concluded that the integrity of the LHSI system would not be degraded. The second concern was that the relief valves at the discharge of the LHSI pumps would lift and not reseat. The relief valves discharge to the safeguards building sump and if these relief valves were to remain open during RMT, reactor coolant would not be confined to the containment building and would be discharged to the safeguards building sump. The licensee concluded that the relief valves do not have a history of sticking open after lifting and LHSI pumps are not likely to be restarted with the system idle when in RMT. Lifting of these relief valves when the LHSI pumps are aligned to take a suction from the RWST was not a concern because RWST water contains low levels of contamination.

The inspector also reviewed JCO 2-92-006 which accompanied the safety evaluation for the LHSI system pressure spikes. The JCO stated that the unit may continue to operate provided the LHSI system is routinely vented and bulk RWST level increase is less than .3 gpm. The inspectors concluded that the Safety Evaluation and JCO were adequate and satisfactory for operating the unit with the condition of pressure spikes in the LHSI system. The licensee was aggressively pursuing this issue and plans to perform additional testing to further evaluate LHSI system pressure spikes.

b. Corrective Action For Deviation Report

TS 3.19.A requires, that under accident conditions, the control room envelope be maintained at a positive differential pressure for one hour following the accident to prevent contamination from any containment leakage. Whenever there is a maintenance opening

in the control room envelope or control room envelope integrity is in question, the licensee verifies that the control room envelope can be maintained at a positive differential pressure per procedure MOP-21.3, Control Room and Relay Room Operational Pressure Test, dated July 2, 1992.

During the performance of MOP-21.3 on October 8, 1991, the required differential positive pressure could not be maintained in the control room envelope. The inability to maintain the required pressure was attributed to an unbalanced ventilation alignment in the Unit 1 cable tunnel. The cable tunnels for both units are adjacent to the control room envelope. When the cable tunnel supply fan is off and a cable tunnel exhaust fan is in fast speed, air from the control room envelope leaks into the cable tunnel. This causes a decrease in air pressure such that the required MOP-21.3 pressure in the control room envelope cannot be maintained. Deviation Report, S-91-1521, was written to document this condition and to insure that corrective measures would be implemented. The deviation report also stated that there were not any procedures to govern the operation of the cable tunnel ventilation fans.

The response to the deviation report required the automatic function of the cable valt exhaust fan be repaired so that the supply and exhaust air would be balanced. Also, engineering was to evaluate the conditions during testing to ensure that with the cable tunnel exhaust fan in fast speed the control room envelope remained pressurized. Testing was performed to evaluate the effects on the control room envelope pressure with the cable vault exhaust fan running in fast and slow speed. Results of this testing indicated that control room envelope pressure could be adequately maintained with the fan in slow or fast speed provided there were no maintenance openings in the pressure boundary.

On July 20, operators noted that differential pressure between the control room envelope and adjacent areas was zero. The control room envelope was tested and failed to meet MOP 21.3 acceptance criteria. Operators entered an eight hour action statement in accordance with TS 3.19. The Unit 1 cable tunnel exhaust fan was placed in slow speed and the action statement was exited. Subsequent investigation revealed that the filter for the Unit 1 cable tunnel supply fan was dirty which prevented air flow into the area. With the exhaust fan in fast speed and no supply flow of air into the area, the pressure differential between the control room envelope and cable tunnel area increased which resulted in increased leakage from the control room envelope into the cable vault. For corrective action, MOP-21.3 was changed by procedure change number 92-844 to secure the Units 1 and 2 cable vaults supply and exhaust fans prior to performing the test and then restarting the fans after the test was complete.

The inspectors reviewed the two occurrence of problems associated with maintaining the control room pressure envelope discussed above. The inspectors determined that the causes of the two occurrences were similar in that both resulted from unbalanced cable vault ventilation. However, the cause of the unbalanced flow were for different reasons. The licensee corrective action for the first occurrence, to balance the ventilation system, would not be expected to prevent filter clogging, although periodic testing and rebalancing along with good preventive maintenance of the system could have prevented the second occurrence. The inspectors also found that the engineering determination that continued operation of the cable vault ventilation does not render the control room envelope inoperable was not well understood by the operators since entering and exiting of the action statement as described above was based on known leakage into the cable vault via the ventilation system.

Corrective action for the July 20 occurrence resulted in changes to procedure MOP-21.3. Procedure change number 92-844 was issued to secure the Units 1 and 2 cable vault supply and exhaust fans prior to performing the test and than restarting the fans after the test was complete. Procedure change 92-844 was approved by SNSOC on July 23. The inspectors reviewed the change to MOP 21.3 and concluded that it was inappropriate corrective action. MOP 21.3 had not been utilized since revised. The purpose of MOP 21.3 is to verify that the control room envelope can be maintained at a positive pressure with maintenance openings in the pressure envelope boundary. The inspectors reviewed the previous main control room envelope leakage calculations. They determined that with a hole in the pressure envelope, MOP 21.3 did not demonstrate that the required positive pressure of .05 inches of water could be maintained during an accident scenario where the cable vault ventilation continued to operate unbalanced. After discussing this issue with the licensee, MOP 21.3 was revised to not secure cable vault ventilation during the performance of the test.

c. Operating Experience Review

On July 22, a two inch elbow on a steam line ruptured resulting in a steam leak between the high pressure and low pressure stage of the maine turbine at the Maine Yankee nuclear power plant. The cause of the rupture is believed to be wall thinning due to erosion/corrosion. The inspectors reviewed this event with the licensee.

EPRI developed computerized program CHECMATE and CHEC-NDE are used for the selection of components susceptible to wall thinning and evaluation. However, computerized models have not been developed for all systems in the licensee's erosion/corrosion program. For systems in which computer models have not been developed, the licensee utilizes industry experience and their own experience to determine the selection of components susceptible to wall

thinning. All secondary plant systems including extraction steam, steam drains, feed, condensate, gland steam exhaust and auxiliary steam are in the erosion/corrosion program.

The licensee has inspected all susceptible areas. As previously mentioned the licensee utilized computerized models, industry operating experience, and their own experience to determine the susceptible areas. The licensee plans to have all computerized models completed by 1994, and will schedule inspections based on the models and planned outage schedules.

In 1990, the licensee inspected the Surry piping which is comparable to the Maine Yankee piping that failed on July 22. Results of that inspection indicated that wall thinning was occurring and consequently, portions of the carbon steel piping were replaced with low alloy steel piping. The licensee plans to further improve the system by replacing all effected piping with stainless steel piping during a future outage.

This event was evaluated by the corporate operating experience review program personnel and was an example of a timely and thorough review of operating experience. IR 280,281/92-09 previously identified that Surry had a very pro-active Flow Assisted Corrosion Program.

d. QA Monthly Briefing Results

On August 3, the Site Quality Assurance Manager briefed the inspectors on QA involvement with station activities for the month of July. Items discussed were the switchyard drawing control assessment, polishing building issues, MER-5 problems and involvement, on-site spent fuel cask transportation, and a new initiative to utilize QA inspectors in root cause evaluations teams. The inspectors were informed that the switchyard drawing control assessment was requested by the SNSOC as a result of a recent problem involving a switchyard procedure. The inspectors concluded that QA was actively involved in station activities which had a positive affect on station safety.

Within the area inspected, no violations were identified.

6. Licensee Event Review (92700)

The inspectors reviewed the LERs listed below and evaluated the adequacy of corrective action. The inspectors' review also included followup on the licensee's implementation of corrective action. Corrective actions were properly implemented or were being properly tracked. The LERs discussed below involve main control room chiller failures. Upgrade of this system to increase operational flexibility and improve the capability to withstand single failures is in progress and involves the installation of two additional 50% capacity chillers.

a. (Closed) LER 280,281/91-08, Two Main Control Room/Emergency Switchgear Room Chillers Inoperable Due to Relay Failure and Inoperable Emergency Source. This issue involved two out of the three main control room chillers being inoperable at the same time. Since TSs only allow one chiller to be inoperable for a period not to exceed seven days, a six hour LCO to hot shutdown was entered when the two chillers became inoperable. Chiller VS-E-4A was declared inoperable after it tripped and could not be restarted. At the time chiller VS-E-4A failed, the emergency power supply, No. 3 EDG, to chiller VS-E-4B, was not available due to planned maintenance and therefore VS-E-4B was also declared inoperable. The problem with chiller VS-E-4A was determined to be the reset relay for the oil pressure/overload trip. This relay was replaced and the six hour LCO exited. The licensee concluded that the relay coil failed due to age-related degradation.

b. (Closed) LER 280,281/91-15, Two Main Control Room/Emergency Switchgear Room Chillers Inoperable Due to Thermostat Failure and Inoperable Emergency Power Source. This issue involved two out of the three main control room chillers being inoperable at the same time. Since TSs only allow one chiller to be inoperable for a period not to exceed seven days, a six hour LCO to hot shutdown was entered when the two chillers became inoperable. Chiller VS-E-4A tripped and was declared inoperable. At the time chiller VS-E-4A failed, the emergency power supply, No. 2 EDG, to chiller VS-E-4C, was not available due to planned maintenance and therefore VS-E-4C was also declared inoperable. The problem with chiller VS-E-4A was determined to be a failure of the thermostat which controls the loading and unloading of the chiller based on chilled water exit temperature. No. 2 EDG was returned to service and chiller VS-E-4C was declared operable which terminated the six hour LCO. Within several days, the thermostat on chiller VS-E-4A was replaced and the chiller was declared operable. CTS items 1462 and 1662 were opened to identify the cause of the thermostat failure.

c. (Closed) LER 280,281/91-16, Two Main Control Room/Emergency Switchgear Room Chillers Inoperable Due to Thermostat Replacement and Inoperable Chiller Service Water Pump. This issue involved two out of the three main control room chillers being inoperable at the same time. Since TSs only allow one chiller to be inoperable for a period not to exceed seven days, a six hour LCO to hot shutdown was entered on both units when the two chillers became inoperable. Chiller VS-E-4C tripped and was declared inoperable. At the time, chiller VS-E-4C failed, chiller VS-E-4A was inoperable due to a failed thermostat which was discussed in the previous paragraph. The thermostat was replaced on chiller VS-E-4A and the six hour LCO was exited. The problem with chiller VS-E-4C was determined to be a failed service water pump motor due to an open phase. The service water pump was replaced and the

chiller was returned to service. CTS item 1441 was opened to identify the cause of the SW pump failure.

Within the areas inspected, no violations were identified.

7. Exit Interview

The results were summarized on July 11, with those individuals identified by an asterisk in Paragraph 1. The following summary of inspection activity was discussed by the inspectors during this exit:

Item Number	Status	Description
IFI 280,281/92-17-01	(Open)	Gas Void Long-Term Corrective Action (paragraph 5.b).
LER 280,281/91-08	(Closed)	Two Main Control Room/Emergency Switchgear Room Chillers Inoperable Due to Relay Failure and Inoperable Emergency Source (paragraph 6.a).
LER 280,281/91-15	(Closed)	Two Main Control Room/Emergency Switchgear Room Chillers Inoperable Due to Thermostat Failure and Inoperable Emergency Power Source (paragraph 6.b).
LER 280,281/91-16	(Closed)	Two Main Control Room/Emergency Switchgear Room Chillers Inoperable Due to Thermostat Replacement and Inoperable Chiller Service Water Pump (paragraph 6.c).

The licensee acknowledged the inspection conclusions with no dissenting comments. The licensee did not identify as proprietary any of the materials provided to or reviewed by the inspectors during this inspection.

8. Index of Acronyms and Initialisms

AFW - AUXILIARY FEEDWATER
CCW - COMPONENT COOLING WATER
CH/HHSI- CHARGING HIGH HEAD SAFETY INJECTION
CSD - COLD SHUTDOWN
DR - DEVIATION REPORT
ECCS - EMERGENCY CORE COOLING SYSTEM
ECP - ESTIMATED CRITICAL POSITION
ESF - ENGINEERED SAFETY FEATURE

GPM	-	GALLONS PER MINUTE
HEPA	-	HIGH EFFICIENCY PARTICULATE AIR
HHSI	-	HIGH HEAD SAFETY INJECTION
IR	-	INSPECTION REPORT
JCO	-	JUSTIFICATION FOR CONTINUED OPERATION
LCO	-	LIMITING CONDITION FOR OPERATION
LEOF	-	LOCAL EMERGENCY OPERATIONS FACILITY
LER	-	LICENSEE EVENT REPORT
LHSI	-	LOW HEAD SAFETY INJECTION
MFW	-	MAIN FEEDWATER
MER	-	MECHANICAL EQUIPMENT ROOM
MOV	-	MOTOR OPERATED VALVE
NAF	-	NUCLEAR ANALYSIS AND FUELS GROUP
OP	-	OPERATING PROCEDURE
PSIG	-	POUNDS PER SQUARE INCH GAUGE
PRT	-	PRESSURIZER RELIEF TANK
QA	-	QUALITY ASSURANCE
RCS	-	REACTOR COOLANT SYSTEM
RHR	-	RESIDUAL HEAT REMOVAL
RMT	-	RECIRCULATION MODE TRANSFER
RWST	-	REFUELING WATER STORAGE TANK
SI	-	SAFETY INJECTION
SNSOC	-	STATION NUCLEAR AND SAFETY OPERATING COMMITTEE
SW	-	SERVICE WATER
TB	-	TURBINE BUILDING
TS	-	TECHNICAL SPECIFICATIONS