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REGION II

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Report Nos.: 50-280/99-04, 50-281/99-04

Licensee: Virginia Electric and Power Company (VEPCO)

Facility: Surry Power Station, Units 1 & 2

Location: 5850 Hog Island Road
Surry, VA 23883

Dates: May 23 - July 3, 1999

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Enclosure

EXECUTIVE SUMMARY

Surry Power Station, Units 1 & 2 NRC Integrated Inspection Report Nos. 50-280/99-04, 50-281/99-04

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a six-week period of resident inspection; in addition, it includes the results of announced inspections by three regional inspectors and a senior reactor analyst.

Operations

- The Unit 2 startup following a refueling outage was performed in a well-controlled manner and in accordance with operating procedures. The estimated critical position calculation accurately predicted reactor criticality (Section O1.2).
- The inspectors reviewed Standing Order 99-001, "Main Station Battery," and determined that the temporary measures effectively controls battery charger operation until the completion of an engineering evaluation to determine the adequacy of Technical Specification requirements (Section O1.3).

Maintenance

- Maintenance activities for the replacement of an emergency diesel generator air compressor pressure switch, reactor coolant filter and boric acid blending summator were properly performed. Personnel conducting the activities were knowledgeable and followed work package instructions. The tagout for the pressure switch was correctly implemented (Section M1.1).
- Seven routine periodic tests observed were properly performed. The tests were properly approved by station management, test procedures were followed by knowledgeable workers and Technical Specification requirements were satisfied (Section M1.2).
- The licensee appropriately returned the Unit 1 A reactor trip breaker to service following repair of its auxiliary contact linkage which had caused an incorrect breaker closed position indication. Inspection of the remaining reactor trip breakers did not reveal any similar linkage problems. The linkage problem would not have affected the opening function of the reactor trip breakers (Section M1.3).
- Documentation of inservice examination activities including the A Steam Generator eddy current examinations and flow-accelerated corrosion examinations was in accordance with approved procedures. Discontinuities were properly recorded, evaluated, and dispositioned. The quality of radiographic film and welding for replacement components was very good. Code repair packages were descriptive and complete. Inspection requirements for ASME Class 2, suction piping running from the refueling water storage tank were properly implemented (Section M1.4).
- Licensee actions taken to address Stone & Webster recommendations for minimizing flooding in the turbine building were found to be satisfactory (Section M1.4).

Engineering

- The inspectors reviewed a temporary plant modification which modified the hot leg temperature circuitry to compensate for a failed temperature detector. No discrepancies were identified (Section E1.1).
- Engineers effectively evaluated industry operating experience and implemented corrective actions to address two issues. Controls were established for monitoring and venting the safety injection system to prevent gas binding events. Non-conservative inputs in dose calculations for main steam line breaks and steam generator tube rupture accidents were analyzed and it was determined that the dose projection remained within 10 CFR 100 and 10 CFR 50 Appendix A, Criterion 19 guidelines (Section E1.2).
- An unresolved item was opened to review and evaluate the licensee's conclusions regarding compliance with Technical Specification 3.19, "Main Control Room Bottled Air System," as it relates to being able to maintain a positive differential pressure in the control room envelope of 0.05 inches of water with respect to adjoining areas of the auxiliary, turbine, and service buildings for one hour when the control room is isolated under accident conditions (Section E1.3).

Plant Support

- During the past three-year period the facility's fire prevention and protection programs were effective in preventing the occurrence of significant plant fires. When fire conditions were identified, mitigating actions were taken in a timely manner so as to limit the damage and prevent serious exposure to safety-related equipment or cables. Plant fire incident reports met fire protection program requirements (Section F1.1).
- The personal protective fire fighting equipment provided to the fire brigade met the facility's fire protection program procedural requirements, was maintained in good condition, and provided a sufficient level of personal safety needed to handle onsite fire emergencies. Backup lighting installed at the fire brigade staging dress out area provided an adequate level of lighting in support of fire brigade operations (Section F2.1).
- The material condition of the plant fire protection features was in accordance with fire protection program requirements. Appropriate corrective actions were being taken to address battery powered emergency lighting and fire door issues identified by the licensee (Section F2.2).
- Fire brigade pre-fire strategies properly reflected as-built plant conditions, provided clear and sufficient fire brigade instructions and met the requirements of the fire protection program (Section F3.1).
- The practice of allowing walk through drills to be used to fulfill annual fire drill requirements for the fire brigade is identified as an unresolved item pending additional review by the NRC (Section F5.1).

- The fire brigade demonstrated good response and fire fighting performance during a simulated fire brigade drill conducted during this inspection. Control room activities in response to the drill were timely and in accordance with appropriate fire contingency operating procedures (Section F5.2).
- A fire brigade drill program vulnerability was identified in that fire brigade drills had not been performed since 1994 in the most risk significant (based on fire induced core damage frequency) area of the plant (Section F5.2).

Report Details

Summary of Plant Status

Unit 1 operated at power the entire reporting period.

Unit 2 commenced the reporting period in a scheduled refueling outage. The unit was returned to service on May 30, 1999, and operated at power for the remainder of the reporting period.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)

The inspectors conducted frequent control room tours to verify proper staffing, operator attentiveness, and adherence to approved procedures. The inspectors attended daily plant status meetings to maintain awareness of overall facility operations and reviewed operator logs to verify operational safety and compliance with Technical Specifications (TSs). Instrumentation and safety system lineups were periodically reviewed from control room indications to assess operability. Frequent plant tours were conducted to observe equipment status and housekeeping. Deviation reports (DRs) were reviewed to assure that potential safety concerns were properly reported and resolved. The inspectors found that daily operations were generally conducted in accordance with regulatory requirements and plant procedures.

O1.2 Unit 2 Reactor Startup From a Refueling Outage (RFO)

a. Inspection Scope (71707)

The inspectors observed Unit 2 startup activities, initial criticality, and connecting the unit to the electrical grid.

b. Observations and Findings

On May 25, 1999, the inspectors observed the approach to criticality following the completion of a scheduled Unit 2 RFO. The evolution was well controlled and criticality was achieved within the allowed band of the estimated critical position calculation. The inspectors observed portions of low power physics testing to verify procedure requirements were met.

During secondary plant startup, the licensee was unable to maintain vacuum in the condenser when steam was admitted through the steam dumps or the turbine. The inspectors monitored troubleshooting efforts and observed plant evolutions from the main control room. Two air leaks in the condenser were identified and a temporary vacuum pump was attached to the condenser. After the air leaks were repaired, the

licensee was able to maintain sufficient vacuum to start the turbine without the use of the temporary vacuum pump. Once the turbine was rolling, vacuum was restored to acceptable levels.

After correction of the vacuum problems and while the turbine was rotating unloaded at 1800 rpm, a turbine seal oil low pressure alarm was received in the main control room and the air side seal oil backup pump autostarted. At the same time, it was reported that oily smoke or mist was coming from the generator seals. After noting that generator hydrogen pressure was steadily decreasing, the operators manually tripped the turbine, evacuated the turbine deck, and vented the hydrogen from the generator. Troubleshooting efforts indicated that a plugged filter caused the seal oil pressure to decrease and resulted in the release of hydrogen through the seals. After the filter was replaced and the generator seals were air tested, the generator was pressurized with hydrogen and the turbine was restarted.

The inspectors also observed the power increase above five percent power and the placement of the unit online at 10:25 a.m. on May 30, 1999. The evolution was well controlled and performed in accordance with approved procedures.

c. Conclusions

The Unit 2 startup following a refueling outage was performed in a well-controlled manner and in accordance with operating procedures. The estimated critical position calculation accurately predicted reactor criticality.

O1.3 Main Station Battery Chargers

a. Inspection Scope (71707)

The inspectors reviewed Standing Order 99-001, "Main Station Battery."

b. Observations and Findings

Each unit at Surry has two station batteries, each with two battery chargers. The Technical Specifications require that two battery chargers be available during unit operation, one for each battery. Nuclear engineering determined that no analysis exists to demonstrate that a single battery charger has sufficient capacity to restore a battery to a full charge while supplying normal steady state loads following a design basis event (loss of offsite power). Preliminary analysis has not been able to demonstrate the acceptability of a single charger. A detailed engineering evaluation of battery charger capacity has been initiated.

In accordance with NRC Administrative Letter 98-10, "Dispositioning of Technical Specifications that are Insufficient to Assure Plant Safety," the licensee has instituted administrative controls until the completion of the engineering evaluation. Standing

Order 99-001 was instituted to limit the amount of time a single battery charger is allowed to remain out of service to 24 hours and require that both chargers on the other station battery remain operable. The inspectors determined that the standing order effectively controls the operation of the battery chargers while the engineering evaluation is performed.

c. Conclusions

The inspectors reviewed Standing Order 99-001, "Main Station Battery," and determined that the temporary measures effectively controls battery charger operation until the completion of an engineering evaluation to determine the adequacy of Technical Specification requirements.

O8 Miscellaneous Operations Issues (92700 and 92901)

- O8.1 (Closed) Licensee Event Report (LER) 50-281/97004-00: Invalid MSTV indication results in manual reactor trip with ESF actuation. On December 2, 1997, Unit 2 was manually tripped when the annunciator for closure of the main steam trip valve (MSTV) was received and MSTV A position lights indicated intermediate position. The valve was later determined to be full open and no signals were present to close the valve. Additional complications (six control rods not indicating less than ten steps and two steam generator power operated relief valves opening due to reactor coolant system (RCS) temperature increasing) occurred with the reactor trip and were described in NRC Inspection Report No. 50-281/97-12.

The incorrect control room indication resulted when the open limit switch arm on MSTV A became inadvertently displaced below the valve position bar. The root cause evaluation (RCE) attributed the trip to an inadequate design, in that, the open limit switch arm had marginal overlap with the valve position bar. Corrective actions were completed to increase the overlap. The RCE determined the displacement was probably caused by maintenance personnel performing insulation activities in the vicinity of the valve. The evaluation team noted that the insulation activity was identified as a potential trip hazard during the prejob briefing. However, the critical components to be avoided were not identified. The corrective actions included adding requirements to the insulation procedure to identify critical components in the work area.

The inspectors identified that the RCE did not recognize a lack of communication as a deficiency and a contributing factor for this event. Although the work activity was identified as a potential trip hazard, the operations shift supervisor, who was aware of the insulation work, did not inform the control room operators of the activity. This resulted in key information not being available to the operator when the alarm annunciated. Operation management stated the expectation was that this information should have been communicated to the operating crew. Operators responded safely and conservatively to the annunciators.

The corrective actions were adequate to address the LER and prevent recurrence.

- O8.2 (Closed) LERs 50-280, 281/97009-00 and 01: Intake canal level probes inoperable due to marine growth. These LERs described a common mode failure resulting in the inoperability of all four intake canal level probes. Specifically, marine growth (hydroids and barnacles) was accumulating on the probes and preventing them from functioning properly. The inspectors reviewed the RCE and corrective actions associated with this event. The licensee implemented increased inspections and cleaning of the canal level probes and provided instructions to reactivate the protective coating on the probes. In addition, the item equivalency administrative procedures, used for similar but not identical component replacement, were revised to improve the incorporation of vendor recommendations into the preventive maintenance program. The inspectors verified that identified corrective actions were implemented and were effective in preventing the accumulation of hydroids. However, another form of marine fouling resulted in level probe inoperability in July 1998 and resulted in LERs 50-280, 281/98010-00 and 01 (see Section O8.3).
- O8.3 (Closed) LERs 50-280, 281/98010-00 and 01: Intake canal level probes inoperable due to marine growth. These LERs described a different type of marine fouling of the intake canal level probes than discussed in LERs 50-280, 281/97009-00 and 01 (see Section O8.2). In one instance this fouling resulted in the inoperability of three of the four level probes. Marine fouling due to amphipods had not previously been seen at the station. The amphipods construct mud tubes (in which they live) on the probes causing an insulation effect and resulting in a delayed response time. The licensee designed and constructed a device, consisting of an underwater video camera and a hydro laser nozzle, to inspect and clean the probes. This device has proven successful in the identification and removal of marine growth in its initial stages. The licensee has established a preventive maintenance task to periodically (approximately every two weeks during the warm weather months, March - November) inspect and clean the probes to ensure operability. The licensee is also evaluating replacement of the canal level probes with another form of level indicating device.
- O8.4 (Closed) Inspection Followup Item (IFI) 50-280, 281/97010-01: Review canal level probe RCE and corrective actions. This IFI was opened to review the licensee's corrective actions related to marine fouling of canal level probes. These events resulted in LERs 50-280, 281/97009-00 and 01 and 50-280, 281/98010-00 and 01. The inspectors reviewed the licensee's Category 1 RCEs 97-2886 and 98-1750 related to marine fouling of the canal level probes. The corrective actions related to these events are discussed in Sections O8.2 and O8.3. The inspectors concluded that the licensee, through their program of inspecting and cleaning the probes, has adequately addressed this issue to prevent recurrence.

II. Maintenance

M1 Conduct of Maintenance

M1.1 Observation of Maintenance Activities

a. Inspection Scope (62707)

The inspectors observed portions of the following work orders (WOs):

- 412182-01 Replace air pressure switch on number 1 emergency diesel generator (EDG) air compressor
- 378527-17 Replace reactor coolant filter 2-CH-FL-002
- 411859-02 Replace signal summator in boric acid blending system

b. Observations and Findings

All work had been properly approved by the operations department and was included on the plan of the day or the outage schedule. The inspectors found that the work performed under these activities was professional and thorough. The work was performed with the work package present and in use. Accompanying documents such as procedures and supplemental work instructions were properly followed. Personnel were experienced, properly trained, and knowledgeable of their assignments. Tagout number 1-99-EG-004 for the number 1 EDG air compressor pressure switch was reviewed and found to be properly prepared and authorized. The tagged components were in the required positions and the tags were properly installed.

c. Conclusions

Maintenance activities for the replacement of an emergency diesel generator air compressor pressure switch, reactor coolant filter and boric acid blending summator were properly performed. Personnel conducting the activities were knowledgeable and followed work package instructions. The tagout for the pressure switch was correctly implemented.

M1.2 Periodic Test (PT) Observations

a. Inspection Scope (61726)

The inspectors observed the performance of portions of the following PTs:

- | | |
|-----------------------|---|
| • 2-IPT-FT-RP-SI-001B | Train B Safeguards Actuation Logic Functional Test |
| • 2-NPT-RX-008 | Core Physics Testing |
| • 0-OPT-SW-001 | Emergency Service Water Pump 1-SW-P-1A |
| • 0-OSP-VS-007 | Control Room Envelope Sequential System Pressure Test |

- 0-NSP-CW-001 High Level Intake Structure Canal Level Probes Inspection
- 1-OSP-TM-004 Turbine Trip Test
- 1-OSP-TM-001 Turbine Inlet Valve Freedom Test

b. Observations and Findings

The inspectors verified that the tests were properly approved by management and included on the plan of the day. The inspectors checked selected components for their pre-test and post-test positions to ensure that they were properly positioned and no discrepancies were identified. The inspectors checked test instruments to ensure proper calibration and that the due dates had not expired. When the tests affected TS components, the inspectors ensured that appropriate TS actions statements were implemented. The inspectors also reviewed the test acceptance criteria to ensure they were consistent with TS requirements. The inspectors reviewed selected test data after the completion of the test to ensure component performance was satisfactory.

During test performance, the inspectors evaluated procedure adherence and worker knowledge of the assigned activities. The inspectors found the testing work practices to be satisfactory.

c. Conclusions

Seven periodic tests observed were properly performed. The tests were approved by station management, test procedures were followed by knowledgeable workers and Technical Specification requirements were satisfied.

M1.3 Reactor Trip Breaker (RTB) Auxiliary Contact Snap Ring Failure

a. Inspection Scope (71707, 62707)

The inspectors reviewed the licensee's resolution to a problem with the Unit 1 A RTB.

b. Observations and Findings

On June 1, during the performance of 1-PT-8.1, "Reactor Protection System Logic," an indication anomaly was observed when the A RTB was locally closed after A train testing. Although the A RTB was closed, the light indications in the main control room and instrumentation racks continued to indicate that the breaker was open. The licensee investigated the matter and determined that the auxiliary switch contacts in the breaker did not actuate because the linkage connecting the auxiliary switch contacts to the main breaker operating mechanism became disconnected. A snap ring retainer which holds the auxiliary switch contact actuating arm in place became dislodged and was found laying in the bottom of the breaker. When inspected, the snap ring appeared flexed and deformed.

The operating shift declared the A RTB inoperable and the appropriate TS action statement was entered. The auxiliary contact switch linkage on the B reactor trip bypass breaker (RTBB) was inspected and found to be intact. The B RTBB was properly tested and put in service to replace the A RTB.

Through questioning the system engineer and by reviewing the breaker drawings, the inspectors determined that the linkage problem described above would not have prevented a RTB from performing its safety function to open. The A RTB was capable of performing its opening function prior to the test as demonstrated by the A RTB successfully opening on a test signal during the performance of 1-PT-8.1.

Licensee management stated that the remaining RTBs and RTBBs installed in the two units would be inspected for a similar problem at the next available opportunity, i.e., the next scheduled performance of 1(2)-PT-8.1. However, the licensee did not inspect the Unit 2 reactor trip breakers for a similar problem at the first available opportunity. On June 16, 2-PT-8.1 was performed but the inspection of the RTBs was not performed until approximately two weeks later. The inspectors discussed the matter with licensee management who stated that the failure to perform the inspection of the Unit 2 RTBs at the first available opportunity did not meet expectations. No similar linkage problems were found on either unit's RTBs and RTBBs, but the snap ring retainer was replaced on each reactor trip breaker. The licensee has not definitively determined the root cause of the event. The RCE is being tracked in the corrective action program with DR S-99-1500.

c. Conclusions

The licensee appropriately returned the Unit 1 A reactor trip breaker to service following repair of its auxiliary contact linkage which had caused an incorrect breaker closed position indication. Inspection of the remaining reactor trip breakers did not reveal any similar linkage problems. The linkage problem would not have affected the opening function of the reactor trip breakers.

M1.4 Inservice Inspection (ISI) - Observation of Work Activities

a. Inspection Scope, Unit 2, (73753)

The inspectors reviewed radiographic film for ASME Code Class 1 & 2 welds and completed documentation for ultrasonic, eddy current, liquid penetrant, and magnetic particle examinations. In addition, examination requirements for piping running from the refueling water storage tank (RWST) to the containment spray pump, the charging pumps and the low head safety injection pumps were verified to be properly implemented in accordance with the ISI program; work packages for two Code repairs were reviewed; and corrective actions taken by the licensee to address Stone & Webster recommendations for minimizing flooding in the turbine building were examined.

b. Observations and Findings

The Code of Record for the third 10-year ISI interval for Unit 2 is the 1989 Edition of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section XI, Division 1. The inspectors reviewed radiographic film for the seven ASME Class 1 & 2 welds listed below:

- Line No. 14" WFPD-117-601, Weld Joint No. W1-22A
- Line No. 14" WFPD-117-601, Weld Joint No. W1-21A
- Line No. 3" SI-272-1503, Weld Joint No. W2-09A
- Line No. 3" SI-272-1503, Weld Joint No. W2-08B
- Line No. 3" SI-272-1503, Weld Joint No. W2-28A
- Line No. 6" RC-317-1502, Weld Joint No. W1-04B
- Line No. 6" RC-317-1502, Weld Joint No. W1-05B

The inspectors verified that the film quality and weld quality met the applicable Code requirements and that the examiners were properly certified.

Outage plans, examination procedures, eddy current guidelines, examiner certifications and a representative sample of completed documentation were reviewed by the inspectors for the A Steam Generator eddy current examinations, the Unit 2 flow-accelerated corrosion examinations, and the ASME Section XI, ISI nondestructive test examinations, which were performed during the spring 1999 RFO. This review revealed that examinations had been documented in accordance with approved procedures. The inspectors also verified that examination personnel with the proper level of qualification and certification were performing the various examination activities. Examination results, evaluation of results, and corrective actions, repairs or replacements were recorded as specified in the applicable program and nondestructive examination procedures.

From the review of two Code repair packages, the inspectors determined that approved procedures were followed, welding and nondestructive tests were satisfactorily performed, and the specified personnel were properly certified for the task they performed. The repairs chosen for this review were Work Order 00409274-02 (replacement of ASME Class 1 Valve No. 02-SI-79) and Work Order 00409287-05 (replacement of ASME Class 2 Valve No. SI-MOV-2869A).

The inspectors also verified that differences in inspection requirements from the 2nd 10-year to the 3rd 10-year ISI program interval for Class 2 piping were properly implemented for the suction piping from the RWST to the containment spray pumps, the charging pumps and the low head safety injection pumps.

Licensee actions taken to address Stone & Webster recommendations for minimizing flooding in the turbine building were also examined. These recommendations were found in the Surry 1 & 2 Individual Plant Examination, Final Report, dated August 1991. The inspectors verified that modifications, preventive maintenance procedures, inspection frequencies, and expansion joint replacement frequencies developed in response to these recommendations were satisfactorily implemented.

c. Conclusions

Documentation of inservice examination activities including the A Steam Generator eddy current examinations and flow-accelerated corrosion examinations was in accordance with approved procedures. Discontinuities were properly recorded, evaluated, and dispositioned. The quality of radiographic film and welding for replacement components was very good. Code repair packages were descriptive and complete. Inspection requirements for ASME Class 2, suction piping running from the RWST were properly implemented.

Licensee actions taken to address Stone & Webster recommendations for minimizing flooding in the turbine building were found to be satisfactory.

M8 Miscellaneous Maintenance Issues (92700, 92902)

- M8.1 (Closed) EA 50-280, 281/97-055 01023: Failure to Establish Adequate Performance Criteria for Monitoring Systems Resulting in Inadequate Implementation of the Maintenance Rule. During the baseline Maintenance Rule inspection, the licensee had not adequately derived the Maintenance Rule performance criteria from the probabilistic risk analysis (PRA) model. As corrective action to this violation the licensee established a Maintenance Rule Recovery Team to redevelop and properly implement the Maintenance Rule. As part of this effort the licensee established new performance criteria for reliability and availability. Using the most current PRA model, S7B, the licensee performed a sensitivity study, documented in calculation SM-1180 dated March 2, 1999, which indicated that the performance criteria had been adequately derived from the PRA. The sensitivity study was highly conservative by using the combined reliability and availability performance criteria as input to the PRA. The core damage frequency increased to $9.7E-5$ from the baseline core damage frequency of $3.8E-5$ in the sensitivity study.
- M8.2 (Closed) IFI 50-280, 281/97009-02: Emergency Service Water (ESW) Pump Corrective Action Followup. This item was issued to provide for followup of the licensee's corrective actions to improve reliability of the ESW pumps. For several years prior to 1997, the licensee experienced functional failures of the ESW pumps during required testing. These failures were due to pump low flow conditions which were caused by bio-fouling of the flow instrumentation and the pumps themselves. The occurrence of a failure in September 1997 led the licensee to classify the ESW pumps as a(1) under the Maintenance Rule, thereby requiring enhanced corrective actions and the establishment of goals and monitoring as required by the Maintenance Rule. Several corrective actions were accomplished which included: modification to the instrumentation, which allowed retraction of the annubars from the flow path preventing fouling during pump start; improved cleaning techniques, which enabled cleaning of previously inaccessible pump internals; and improved scheduling of pump cleaning and testing, which resulted in improved pump reliability. Once the licensee was able to improve the ESW pump reliability, the a(1) goals allowed the pumps to be returned to an a(2) status under the Maintenance Rule. The licensee continues to closely monitor pump performance, and plans additional corrective actions to reduce bio-fouling by copper coating the pump

impellers. The licensee's corrective actions have been able to maintain the pumps in an operable status, and, as a result, no additional followup of this issue is necessary.

- M8.3 (Closed) IFI 50-280, 281/97001-01: Followup Licensee Actions to Strengthen Risk Assessment for On-line Maintenance Activities. The licensee revised Virginia Power Administrative Procedure (VPAP)-2001, "Station Planning and Scheduling," to include the limitations of the original risk matrix. The matrix indicated select equipment out-of-service (OOS) conditions that had been evaluated using the PRA model. Based upon the numerical results, a particular color with corresponding management approvals and maximum acceptable time duration of the OOS configuration were delineated in the matrix. However, all OOS configurations could not be identified via the risk matrix. Therefore, additional direction was included in the VPAP as to how to evaluate or who to contact when OOS conditions beyond the risk matrix were encountered.

Also, the licensee was beginning to use a computerized on-line risk monitor to evaluate risk prior to removing equipment from service. The licensee had performed validations between the on-line computerized model results and the full-scope PRA model/VPAP risk matrix with good agreement. One scheduler was the "lead" in using the computerized model and was documenting limitations and problems being encountered in using the computerized on-line risk monitor. The Shift Technical Advisors had received limited training in using the on-line risk monitor and had been tasked to use the monitor in parallel with the VPAP risk matrix for emergent OOS configurations. The licensee recognized that further efforts were needed to use the on-line risk monitor exclusive of the VPAP risk matrix and the administrative controls associated with using the risk matrix. While evaluating hypothetical out of service conditions with the on-line risk monitor the inspectors and the licensee observed one OOS condition where the configuration was unrestricted from a core damage perspective but was restricted from a large early radiological release frequency (LERF) perspective. LERF is a special feature of the on-line risk monitor and is not required to be considered under the licensee's program and is generally not considered by other licensees. The licensee indicated that they would evaluate the implications of LERF in their on-line risk process.

III. Engineering

E1 Conduct of Engineering

E1.1 Unit 2 Hot Leg Resistance Temperature Detector

a. Inspection Scope (37551)

The inspectors reviewed the implementation of Temporary Modification S2-99-02, "Unit 2, Loop A T_{HOT} Average Summator."

b. Observations and Findings

During plant heatup following the Unit 2 RFO, the licensee experienced a failure of the primary and backup elements of resistance temperature detector (RTD) 2-RC-TE-2412,

one of the three hot leg temperature detectors on the A coolant loop. The output of this RTD is averaged with two other detectors to provide an accurate indication of hot leg coolant temperature. The licensee was unable to install a replacement RTD and a temporary modification was developed to temporarily plug the RTD well and modify the plant instrumentation circuitry to provide two-sensor averaging for indication of hot leg temperature. The inspectors reviewed the modification, including the 50.59 evaluation, and no discrepancies were noted.

c. Conclusions

The inspectors reviewed a temporary plant modification which modified hot leg temperature circuitry to compensate for a failed temperature detector. No discrepancies were identified.

E1.2 Engineering Evaluation of Industry Operating Experience

a. Inspection Scope (37551)

The inspectors reviewed the licensee's evaluation and corrective actions associated with industry operating events. The inspectors focused on gas binding of safety injection pumps and dose calculations for main steam line breaks and steam generator tube rupture accidents.

b. Observations and Findings

The issue of gas binding of safety injection pumps has been communicated through NRC Information Notice 88-23, Supplements 1 through 5, and various industry communications. Based on industry experience, 10 additional vent valves were added to the safety injection system. Using procedure 1/2-OSP-SI-001, operators vent 17 areas of the safety injection system quarterly. Per procedure, if operators identify any gas in the system, the gas is quantified and the system evaluated for operability. Through procedural review, the inspectors noted that no gas was identified in the system for the last 18 months. During the inspection period, operators identified and the system engineers properly evaluated a small amount of gas on the discharge piping for the safety injection pumps. The inspectors determined through field walkdowns that vent valves were appropriately placed at high points in the system. The inspectors concluded that system engineers addressed the industry gas binding issue through venting and monitoring of the safety injection system.

Based on industry experience, DR S-99-0725 was generated to evaluate the current calculations for iodine spiking source term rates. Industry information indicated that non-conservative assumptions were used in the calculations. The nuclear engineers determined that the non-conservative assumptions were also used in Surry Power Station dose calculations. The following parameters were non-conservative: 1) letdown system flow; 2) letdown purification efficiency; 3) reactor coolant system leakage; and 4) reactor coolant system temperature. Based on initial calculations at Surry Power Station and detailed calculations at North Anna Power Station, nuclear engineers estimated that

the dose for a steam generator tube rupture and main steam line breaks would increase by a factor of 2.4. This resultant dose remains well within 10 CFR 100 and 10 CFR 50 Appendix A, Criterion 19 guidelines. Administrative controls to monitor dose equivalent I-131 levels were adequate. The long term corrective action to revise the calculations was being appropriately tracked.

c. Conclusions

Engineers effectively evaluated industry operating experience and implemented corrective actions to address two issues. Controls were established for monitoring and venting the safety injection system to prevent gas binding events. Non-conservative inputs in dose calculations for main steam line breaks and steam generator tube rupture accidents were analyzed and it was determined that the dose projection remained within 10 CFR 100 and 10 CFR 50 Appendix A, Criterion 19 guidelines.

E1.3 Main Control Room Pressure Boundary Issues

a. Inspection Scope (37551)

The inspectors reviewed the licensee's efforts to resolve problems associated with the main control room pressure boundary as required by TS 3.19.A.

b. Observations and Findings

TS 3.19 requires that a bottled dry air bank shall be available to pressurize the main control room to a positive differential pressure of 0.05 inches of water with respect to adjoining areas of the auxiliary, turbine, and service buildings for one hour when the control room is isolated under accident conditions. TS 4.1, Table 4.1-2A, item 15, requires this capability to be demonstrated once per 18 months. This requirement is met through the performance of 0-OPT-VS-005, "Control Room Leakage Test." This test uses the relay room emergency supply fan with a restrictive test orifice plate installed in the fan's discharge to simulate the release of the air bottle system. In October 1998, during the performance of 0-OPT-VS-005 the licensee determined that they were unable to maintain a positive differential pressure of 0.05 inches of water in the main control room with respect to the turbine building. To mitigate this matter, the licensee secured the Unit 1 and 2 cable vault/tunnel supply and exhaust fans. Once the fans were secured (tagged out), the positive differential pressure between the control room envelope and the turbine building was achievable during the performance of 0-OPT-VS-005. The licensee attributed this problem to 1) leakage between the cable vaults/tunnels and the control room envelope and 2) The cable vault/tunnel areas being at a negative pressure relative to the control room envelope due to the cable vault ventilation system being out of balance (exhaust fan flow rate greater than supply fan flow rate). Plans were made to balance the cable vault/tunnel ventilation system and to investigate and repair leakage paths between the two areas while maintaining the cable vault/tunnel ventilation secured.

On June 11, 1999, the cable vault/tunnel fans were returned to service. Post maintenance testing involved the performance of 0-OSP-VS-007, "Control Room Envelope Sequential System Pressure Test." The data obtained during this test was evaluated as acceptable in engineering transmittal S-99-0162. This test did not demonstrate the acceptability of the control room envelope to achieve and maintain 0.05 inches of water positive differential pressure. On June 23, 1999, 0-OPT-VS-005 was performed. Again, a positive differential pressure of 0.05 inches of water between the control room envelope and the turbine building was not achievable for a one hour period. The Unit 1 and 2 cable vault/tunnel supply and exhaust fans were again secured. The licensee initiated troubleshooting to resolve the matter. While investigating the effect of the cable vault ventilation on the control room envelope, local pressure readings were obtained (using a hand held manometer) within various areas adjacent to the control room envelope while in a 0-OPT-VS-005 ventilation lineup (TS testing alignment). Readings taken in the Unit 1 and 2 Cable Spreading Rooms (an area located above and adjacent to the main control room in the service building) indicated that the cable spreading rooms were at a pressure greater than the main control envelope due to cable spreading room ventilation being unbalanced (return flow greater than exhaust flow). To temporarily alleviate this concern, the licensee opened doors between: 1) the Unit 1 cable spreading room and mechanical equipment room number 1, and 2) Unit 2 cable spreading room and mechanical equipment room number 2, to equalize the pressure between the cable spreading rooms and the turbine building. As previously stated, TS 3.19 requires that when the control room is isolated under accident conditions (as is simulated during the performance of 0-OPT-VS-005), a positive differential pressure of 0.05 inches of water with respect to adjoining areas of the auxiliary, turbine, and service buildings shall be maintained for one hour. The licensee is currently evaluating the effects of both the cable vault/tunnel and cable spreading room ventilation systems on the ability of the control room envelope to be maintained at a positive differential pressure and whether TS 3.19 compliance was maintained in the past. Pending the licensee's evaluation and the inspectors' review, this matter will be tracked as Unresolved Item (URI) 50-280, 281/99004-01.

c. Conclusions

An unresolved item was opened to review and evaluate the licensee's conclusions regarding compliance with Technical Specification 3.19, "Control Room Bottled Air System," as it relates to being able to maintain a positive differential pressure in the control room envelope of 0.05 inches of water with respect to adjoining areas of the auxiliary, turbine, and service buildings for one hour when the control room is isolated under accident conditions.

E2 Engineering Support of Facilities and Equipment

E2.1 Year 2000 (Y2K) Readiness Program Review (2515/141)

The staff conducted an abbreviated review of Y2K activities and documentation using Temporary Instruction (TI) 2515/141, "Review of Year 2000 (Y2K) Readiness of Computer Systems at Nuclear Power Plants." The review addressed aspects of Y2K

management planning, documentation, implementation planning, initial assessment, detailed assessment, remediation activities, Y2K testing and validation, notification activities, and contingency planning. The reviewers used NEI/NUSMG 97-07, "Nuclear Utility Year 2000 Readiness," and NEI/NUSMG 98-07, "Nuclear Utility Year 2000 Readiness Contingency Planning," as the primary references for this review.

During the review, the licensee stated that the Y2K Readiness Project assessment and remediation activities were 95 percent complete and contingency planning was 92 percent complete. Both programs were on target to be completed by their scheduled due dates.

A detailed review of the following systems was performed:

- Inadequate Core Cooling Monitor
- Meteorological Tower Equipment
- Surry Radioactive Waste Facility Distributed Control System
- Early Warning System (Sirens)
- Sequence of Events Recorded (Hathaway)
- Plant Security Computer

Conclusions regarding the Y2K readiness of the facility are not included in this report. The results of this review will be combined with the results of reviews of other licensees in a NUREG publication.

IV. Plant Support

R1 Radiological Protection and Chemistry Controls

R1.1 General Observations (71750)

On numerous occasions during the inspection period, the inspectors reviewed radiation protection (RP) practices including radiation control area entry and exit, survey results, and radiological area material conditions. No discrepancies were noted, and the inspectors determined that RP practices were proper.

The primary chemistry logs were reviewed to ensure plant chemistry was within the Technical Specification and procedural limits. No deficiencies were noted.

S1 Conduct of Security and Safeguards Activities

S1.1 General Observations (71750)

On numerous occasions during the inspection period, the inspectors performed walkdowns of the protected area perimeter to assess security and general barrier conditions. No deficiencies were noted and the inspectors concluded that security posts were properly manned and that the perimeter barrier's material condition was properly maintained.

F1 Control of Fire Protection Activities

F1.1 Frequency of Fire Related Incidents and Fire Reports

a. Inspection Scope (64704)

The inspectors reviewed plant fire incident reports and DRs resulting from fire, smoke, sparks, arcing and equipment overheating incidents for the time period 1997-1999 to assess the effectiveness of the fire prevention and protection programs and any maintenance-related or material condition problems with plant systems and equipment that may have initiated these incidents. The inspectors assessed whether plant fire protection requirements were being met in accordance with VPAP 2401, Form No. 723378, "Fire Incident Reports," when fire-related events occurred.

b. Observations and Findings

The licensee's fire reports and DR issues associated with observed fire, smoke, sparks, arcing and equipment overheating indicated that during the period 1997-1998, there were eighteen incidents of fire, smoke or equipment overheating observed within the protected areas of the plant. Three of the incidents required fire brigade response and investigation. The inspectors determined that this indicated an average of about three fire related incidents per reactor year of operation. Fourteen of the eighteen incidents (approximately 80 percent) were related to electrical component faults. Two minor fires had been reported in 1999. The inspectors concluded that during the past three-year period the facility's fire prevention and protection programs were effective in preventing the occurrence of significant plant fires. When fire conditions were identified, mitigating actions were taken in a timely manner so as to limit the damage and prevent serious exposure to safety-related equipment or cables. Plant fire incident reports met fire protection program procedure requirements.

c. Conclusions

During the past three-year period the facility's fire prevention and protection programs were effective in preventing the occurrence of significant plant fires. When fire conditions were identified, mitigating actions were taken in a timely manner so as to limit the damage and prevent serious exposure to safety-related equipment or cables. Plant fire incident reports met fire protection program requirements.

F2 Status of Fire Protection Facilities and Equipment

F2.1 Inspection of Fire Brigade Equipment

a. Inspection Scope (64704)

The inspectors reviewed VPAP 2401, Section 6.6.10, "Fire Brigade Equipment," and toured the fire brigade staging area and inspected fire brigade lockers. The inspection

was conducted to verify that the fire brigade equipment specified in the NRC-approved fire protection program were accessible and available in the staging area and fire brigade lockers.

b. Observation and Findings

Using the fire protection program turnout gear list, the inspectors toured the fire brigade staging area and inspected four fire brigade lockers. The inspectors observed that the equipment was accessible for use. The equipment in the fire brigade staging area and lockers was fire brigade helmets/hoods, turnout coats, pants, boots, gloves, flashlights, radios and self-contained breathing apparatus (SCBA) for each member of the fire brigade. The equipment was in good condition and met fire protection program procedure requirements. The inspectors also observed that there was fixed battery-powered backup lighting installed at the fire brigade staging dress out area in the turbine building hallway. The backup lighting was operable and provided an adequate level of lighting in support of fire brigade operations.

c. Conclusions

The personal protective fire fighting equipment provided to the fire brigade met the facility's fire protection program procedural requirements, was maintained in good condition, and provided a sufficient level of personal safety needed to handle onsite fire emergencies. Backup lighting installed at the fire brigade staging dress out area provided an adequate level of lighting in support of fire brigade operations.

F2.2 Maintenance of Fire Protection Systems and Equipment

a. Inspection Scope (64704)

The inspectors reviewed the last three quarterly (1998-1999) Engineering Status Reports for fire protection systems and features to assess performance trends or material condition problems with fire protection/safe-shutdown systems and equipment. The inspectors conducted walk down tours in four of the highest ranked dominant fire risk locations identified in the licensee's individual plant examination - external events (IPEEE) to determine the material condition of the fire detection/suppression systems, 10 CFR 50 Appendix R emergency lighting, and fire barriers in these plant areas.

b. Observations and Findings

The fire protection records indicated that most of the fire protection issues involved corrective actions in process related to emergency lighting reliability and fire door issues. Fire door issues were being tracked by a station Level 1 action item, No. 13981, "Surry Doors," and the lighting lead-acid batteries were being replaced with newer technology gel-cell types to improve reliability.

During walk down tours, the inspectors observed that the material condition of installed fire protection features was in accordance with fire protection program requirements.

c. Conclusions

The material condition of the plant fire protection features was in accordance with fire protection program requirements. Appropriate corrective actions were being taken to address battery powered emergency lighting and fire door issues identified by the licensee.

F3 Fire Protection Procedures and Documentation

F3.1 Fire Brigade Pre-fire Strategies

a. Inspection Scope (64704)

The inspectors reviewed fire brigade pre-fire strategies for selected plant areas described in Section 6.1.17 and Attachments 18 and 19 of VPAP 2401 for compliance with the NRC-approved fire protection program. Plant tours were also performed to verify the fire strategies reflected as-built plant conditions and potential fire conditions.

b. Observations and Findings

The inspectors reviewed the pre-fire strategies for four high ranked dominant fire risk locations identified in the licensee's IPEEE. Each of the fire fighting strategies and plan drawings addressed the fire potential, area location, means of fire brigade approach, location of available fire protection equipment, fire brigade action, hazards to be considered, ventilation, special notes and instructions, and available communications. During plant tours the inspectors compared the pre-fire strategy plan drawings with as-built plant conditions. No discrepancies were noted. The pre-fire strategies provided clear fire brigade instructions, good graphic layout of the fire areas, accurate information on the available fire protection features and met the requirements of the NRC-approved fire protection program.

c. Conclusions

Fire brigade pre-fire strategies properly reflected as-built plant conditions, provided clear and sufficient fire brigade instructions and met the requirements of the fire protection program.

F5 Fire Protection Staff Training and Qualification

F5.1 Fire Brigade Drill Program

a. Inspection Scope (64704)

The inspectors reviewed the fire brigade training/drill program procedure VPAP-2401, "Fire Protection Program," Revision 11, for compliance with the requirements of the approved fire protection program as described in the Updated Final Safety Analysis Report (UFSAR), Section 9.10.1 and approved in the Facility Operating License.

b. Observations and Findings

The organization and training requirements for the Surry plant fire brigade are established by VPAP-2401, Section 6.6, Paragraph 6.6.12.a, "Fire Brigade Drills." The paragraph states that actual fires, false alarms, and walk through drills when properly critiqued can be used to fulfill annual fire drill requirements. The drill records for 1998 and the first quarter of 1999 were reviewed. These records indicated that in 1998, the licensee conducted five (5) walk through drills that were credited to fulfill annual drill requirements for each of the five operations shifts. The licensee conducted a total of 22 drills in 1998 for these five operations shifts. The walk through fire brigade drills were conducted primarily during the last quarter of 1998, near a RFO. Thus far in 1999, one fire brigade drill conducted was of the walk through type.

The requirements for fire brigade drills are addressed in the Surry Facility Operating License Condition 3.1 for Units 1 and 2. The License Condition states that the licensee shall implement and maintain all provisions of the approved fire protection program as described in the UFSAR and as approved in the Safety Evaluation Report (SER) dated September 19, 1979 (and Supplements). NRC policy regarding fire brigade drills is stated in APCS 9.5-1, "Guidelines for Fire Protection for Nuclear Power Plants Docketed Prior to July 1, 1976," dated August 23, 1976, and clarified in NRC guidelines contained in Section 3.0, "Drills," of "Nuclear Plant Fire Protection Functional Responsibilities, Administrative Controls and Quality Assurance," dated June 14, 1977. This section states that site fire brigade drills should be preplanned to assess fire alarm effectiveness and include an assessment of the fire brigade member's use of fire fighting equipment, including the SCBA. The licensee's conformance to the APCS 9.5-1 policy regarding administration of the fire protection program for the fire brigade was addressed in NRC SER dated September 19, 1979. The inspectors questioned the licensee concerning the basis and application of fire brigade walk through drills that were credited to fulfill annual drill requirements.

The licensee stated that walk through drills are done infrequently and gives the fire brigade a flexible means for training in response to changing plant conditions, typically when plant conditions are sensitive or in an outage. The licensee stated that the plant fire brigade normally responds to actual fires and possible false alarms in full turnout gear and fire brigade personnel wear their SCBA. The licensee stated that walk through fire brigade drills are fire brigade group discussions of a possible fire situation in a plant area and are run like a desktop exercise. The exercise is critiqued by the plant fire protection and training staffs. However, contrary to NRC policy regarding fire brigade drills, these walk through fire brigade drills are not performed in response to fire alarms, do not exercise the fire brigade simulated use of fire equipment, and do not exercise the fire brigade in full turnout gear or the SCBA. Yet, these fire brigade walk through drills were credited to fulfill annual drill requirements for fire brigade members.

The licensee provided the inspectors copies of letters to the NRC dated March 6, 1978, and July 21, 1978, NRC letter dated June 14, 1978, and NRC SER dated September 19, 1979, regarding conformance to NRC policy and staff positions on fire protection. The SER dated September 19, 1979, discussed the fire brigade training program

commitment to: "perform practice sessions which include simulations in plant areas (walk throughs, dry runs) [underlining added for emphasis] of the proper fire fighting methods that could occur in a nuclear power plant. The duplication of actual room configurations in various plant areas will not be required." The SER was silent on any specific deviations from the NRC policy as stated in APCSB 9.5-1 or guidelines concerning the conduct of fire brigade drills. Also, the SER was not clear regarding the intent of the NRC approval of the licensee's commitment for fire brigade training practice sessions and how it might be applicable to defining facility fire brigade drills.

The inspectors were not able to conclude whether the licensee's practice of walk through fire brigade drills being used to fulfill annual fire drill requirements was within the scope of the approved fire protection program. This issue is identified as URI 50-280, 281/99004-02. Resolution of this item will require additional NRC review of the Surry SERs for fire protection and plant specific fire protection correspondence.

c. Conclusions

The practice of allowing walk through drills to be used to fulfill annual fire drill requirements for the fire brigade is identified as an unresolved item pending additional review by the NRC.

F5.2 Fire Brigade Performance During Drill Exercises

a. Inspection Scope (64704)

The inspectors observed control room activities and fire brigade response associated with an unannounced fire brigade drill to evaluate fire brigade performance and the control room use of the fire contingency operating procedures.

b. Observations and Findings

The inspectors witnessed an unannounced fire brigade drill for operations shift B and security shift C, on June 9, 1999. The fire scenario involved a simulated fire in the Unit 2 emergency switchgear room. The response of the fire brigade to the simulated fire included the fire brigade scene leader, four brigade members from operations and security in full turnout gear and with SCBAs. Additional support personnel from various plant departments also responded to the drill. The fire brigade demonstrated aggressive fire fighting tactics and the proper use of fire fighting equipment. Communications between the fire brigade leader and the control room and the brigade members was good. The fire brigade leader's direction and performance were also good. Control room activities in response to the drill were timely and in accordance with appropriate fire contingency operating procedures. A critique to discuss the fire brigade's performance and recommendations for future enhancement was held following the drill.

To evaluate other operating shifts' fire brigade drill performance, the drill critique data for selected shift drills conducted during the past 3-year period was reviewed. The inspectors determined that the average response time for the shift fire brigade to

assemble at the fire scene and attack a fire was about 20 minutes. The licensee's expectation for fire brigade response to a fire is 30 minutes.

The inspectors reviewed the plant IPEEE risk assessment submitted to the NRC on December 15, 1994, in response to Generic Letter 88-20, Supplement 4. The inspectors also reviewed the list of areas in which fire drills had been held during the past 5-year period. The inspectors noted that while the drills were performed in several different risk significant plant areas, a fire drill had not been performed since 1994 in the Service Building Unit 1 Normal Switchgear Room (Fire Area 31). This area, with 30.7% of the total Unit 1 fire induced core damage frequency (CDF), was identified in Section 1.4 of the IPEEE as the most important compartment of the risk significant plant areas. This was considered a fire brigade program vulnerability, in that, infrequent drills did not assure that the brigade was familiar with the fire protection and operational features and fire hazards in this risk significant plant area.

c. Conclusions

The fire brigade demonstrated good response and fire fighting performance during a simulated fire brigade drill conducted during this inspection. Control room activities in response to the drill were timely and in accordance with appropriate fire contingency operating procedures. A fire brigade drill program vulnerability was identified in that fire brigade drills had not been performed since 1994 in the most risk significant (based on fire induced core damage frequency) area of the plant.

F8 Follow up on Plant Support Items (92904)

F8.1 (Closed) EA 50-280, 281/97-474 01013: Failure to Meet Appendix R Requirements.

(Closed) EA 50-280, 281/97-474 01023: Failure to Correct Appendix R Deficiencies.

(Closed) EA 50-280, 281/97-474 02014: Failure to Report Appendix R Deficiencies.

(Closed) Deviation (DEV) 50-280, 281/97009-09: Failure to Meet Commitments to Appendix R for Circuit Breaker Coordination.

The inspectors verified that the six committed actions from the licensee's Appendix R vital bus violation and deviation response dated January 12, 1998, had been completed. These actions included performing plant and procedure modifications, conducting Appendix R awareness training, conducting a multi-utility fire protection assessment, and performing an Appendix R Report review. The inspectors determined that the followup actions from the multi-utility assessment and Appendix R Report review had been placed in the plant corrective action process; and, as of June 9, 1999, were approximately 70% complete.

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on July 14, 1999. The licensee acknowledged the findings presented.

The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

PARTIAL LIST OF PERSONS CONTACTED

M. Adams, Superintendent, Engineering
 R. Allen, Superintendent, Maintenance
 R. Blount, Manager, Operations & Maintenance
 M. Crist, Superintendent, Operations
 E. Grecheck, Site Vice President
 D. Llewellyn, Superintendent, Training
 B. Stanley, Supervisor, Licensing
 T. Sowers, Manager, Station Safety & Licensing
 W. Thornton, Superintendent, Radiological Protection

INSPECTION PROCEDURES USED

IP 37551:	Onsite Engineering
IP 61726:	Surveillance Observation
IP 62707:	Maintenance Observation
IP 64704:	Fire Protection Program
IP 71707:	Plant Operations
IP 71750:	Plant Support Activities
IP 73753:	Inservice Inspection, Observation of ISI Work Activities
IP 92700:	Onsite Followup of Written Reports of Nonroutine Events at Power Reactor Facilities
IP 92901:	Followup - Plant Operations
IP 92902:	Followup - Maintenance
IP 92904:	Followup - Plant Support
TI 2515/141:	Review of Year 2000 (Y2K) Readiness of Computer Systems at Nuclear Power Plants

ITEMS OPENED AND CLOSED

Opened

50-280, 281/99004-01	URI	Review and evaluate the licensee's conclusions regarding compliance with Technical Specification 3.19 as it relates to being able to maintain a positive differential pressure in the control room envelope (Section E1.3)
50-280, 281/99004-02	URI	Review and evaluate the licensee's practice of walk through fire brigade drills being used to fulfill annual fire drill requirements (Section F5.1)

Closed

50-281/97004-00	LER	Invalid MSTV indication results in manual reactor trip with ESF actuation (Section O8.1)
50-280, 281/97009-00 and 01	LER	Intake canal level probes inoperable due to marine growth (Section O8.2)
50-280, 281/98010-00 and 01	LER	Intake canal level probes inoperable due to marine growth (Section O8.3)
50-280, 281/97010-01	IFI	Review canal level probe RCE and Corrective actions (Section O8.4)
50-280, 281/97-055 01023	EA	Failure to Establish Adequate Performance Criteria for Monitoring Systems Resulting in Inadequate Implementation of the Maintenance Rule (Section M8.1)
50-280, 281/97009-02	IFI	Emergency Service Water Pump Corrective Action Followup (Section M8.2)
50-280, 281/97001-01	IFI	Followup Licensee Actions to Strengthen Risk Assessment for On-line Maintenance Activities (Section M8.3)
50-280, 281/97-474 01013	EA	Failure to Meet Appendix R Requirements (Section F8.1)

50-280, 281/97-474 01023

EA

Failure to Correct Appendix R Deficiencies
(Section F8.1)

50-280, 281/97-474 02014

EA

Failure to Report Appendix R Deficiencies
(Section F8.1)

50-280, 281/97009-09

DEV

Failure to Meet Commitments to Appendix R
for Circuit Breaker Coordination (Section
F8.1)