UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W., SUITE 2900
ATLANTA, GEORGIA 30323-0199

Report Nos.: 50-348/95-21 and 50-364/95-21

Licensee: Southern Nuclear Operating Company, Inc.
P.O. Box 1295
Birmingham, AL 35201-1295

Docket Nos.: 50-348 and 50-364 License Nos.: NPF-2 and NPF-8

Facility Name: Farley Nuclear Plant, Units 1 and 2

Inspection Conducted: December 25, 1995 through February 3, 1996

Lead Inspector: For R. W. Wright 3/4/96
T. M. Ross, Senior Resident Inspector Date Signed

Inspectors: M. A. Scott, Resident Inspector
W. M. Miller, Reactor Inspector
E. H. Girard, Reactor Inspector
M. N. Miller, Electrical Inspector
F. N. Wright, Radiation Protection Inspector
R. P. Carrion, Chemistry/Radiological Effluent Inspector

Approved by: P H Skinner 3/4/96
P. H. Skinner, Chief Date Signed
Reactor Projects Branch 2
Division of Reactor Projects

SUMMARY

Scope:

Routine inspections by the resident inspectors were conducted onsite in the functional areas of plant operations, maintenance/surveillance, engineering/technical support and plant support. These inspections included a review of nonroutine events and a follow-up of previous inspection findings. Backshift inspections were conducted on January 1, 2, 3, 6, 8, 9, 15, 25, 27, 30, and 31, and February 1 and 2, 1996. Routine inspections by Region II inspectors were also conducted of the radiation protection program, which included audits of radiation protection activities, external and internal exposure controls, control of radioactive material and contamination, and the as low as reasonably achievable program implementation; the radiological effluents and chemistry programs, which included the organization of the chemistry department, plant water chemistry, radiological effluent releases, the radiological environmental monitoring program and the control room emergency ventilation system; and the closeout inspection of Generic Letter 89-10 implementation.

Results:

Plant Operations

Operations personnel and management maintained good control over routine full power operation of Units 1 and 2, and both units operated well. Shift operators remained attentive to changing plant conditions and were very knowledgeable of plant status and ongoing activities. The Unit 2 ramp down to 15% on January 30 and subsequent return to full power operation on February 1 was well controlled and accomplished without incident. Identification and resolution of plant incidents continues to be conducted in a very effective manner, with one notable exception. The operations department and a root cause team failed to recognize the applicability and implications of the asterisk ("*") condition in technical specifications (TS) during the last Unit 2 start up. This resulted in a noncited violation (report section 2.9). Overall plant housekeeping and physical conditions were adequate. However, numerous rooms in the radiological control area were still without sufficient lighting due to burned out bulbs, and previous licensee efforts to correct this condition have only been partially successful. Housekeeping conditions inside Unit 1 and 2 containments were good.

Maintenance

Maintenance and surveillance activities were consistently performed in accordance with work order instructions, associated procedures, and applicable clearance controls. Responsible personnel demonstrated familiarity with administrative and radiological controls. Surveillance tests were routinely performed in a deliberate step-by-step manner by knowledgeable plant personnel. Safety-related maintenance and testing evolutions were generally well planned and executed. Efforts to resolve high crank case pressure problems with the 1C emergency diesel generator were thorough and comprehensive. One violation was identified for failing to control maintenance personnel overtime pursuant to TS requirements during the last two refueling outages (report section 3.17).

Engineering

Overall engineering and technical support of operations, maintenance, modification, and surveillance activities remained very good. Onsite engineering continued to interface well with the corporate office, and maintained a consistently proactive posture in addressing evolving plant issues. The configuration control board has been very effective in eliminating the backlog of old ideas and design change requests, along with dispositioning new ideas. Nine of twelve outstanding inspector followup items regarding implementation of Generic Letter 89-10 have been closed.

Plant Support

Health Physics (HP) personnel provided positive support of Unit 1 and 2 steady-state operations. Overall, the licensee's radiation protection program was adequately managed and effectively implemented with all individual personnel exposures within 10 CFR Part 20 limits. Recent failure to meet 1995 annual and Unit 1 refueling outage 13 collective dose goals indicated additional attention to the as low as reasonably achievable program activities was needed. HP maintained good control over plant personnel who entered Unit 1 and 2 containments at power. Personnel entry into the protected area was well controlled at the primary access point. Security personnel were consistently alert and implemented the site's security plan in an appropriate manner. Fire protection features were adequately maintained, and compensatory measures were implemented as appropriate. Organization and staffing levels of the chemistry department satisfied TS requirements. One of the values reported in the licensee's radioactive effluent release report for 1994 was found to be significantly greater than those of previous years due to the use of a new computer program, which did not differentiate between natural and man-made radioisotopes in plant releases. Overall the chemistry program was effective at inhibiting degradation due to corrosion/erosion of components of both the primary and secondary systems. Radiological environmental air and water sampling stations, and the control room emergency ventilation system were well maintained and met applicable requirements.

REPORT DETAILS

Acronyms used in this report are defined in paragraph 8.

1.0 PERSONS CONTACTED

1.1 Birmingham, Alabama - January 12, 1996

Southern Nuclear Operating Company:

*M. Ajluni, Manager - Licensing Manager
*C. Campbell, Nuclear Technician
*J. Fridrichsen, Senior Project Engineer, Nuclear Maintenance Support
*S. Gates, Senior Specialist
*J. Kale, Group Supervisor, FNP Maintenance Engineering Support
*J. McGowan, Manager - Safety Audit and Engineering Review
*B. Moore, Manager - Nuclear Maintenance Support
*M. Pilcher, FNP Valve Engineer

Southern Company Services:

*J. Daniels, Senior Designer
*J. Posenecker, Lead Engineer

1.2 Farley Nuclear Plant - February 9, 1996

Southern Nuclear Operating Company Employees:

W. Bayne, Chemistry/Environmental Superintendent
B. Bell, Electrical Maintenance Superintendent
*C. Buck, Technical Nuclear Manager
*R. Coleman, Maintenance Manager
*L. Enfinger, Plant Administration Manager
H. Garland, Mechanical Maintenance Superintendent
*S. Gates, Team Leader - Maintenance Performance Team
D. Grissette, Operations Manager
*R. Hill, General Manager - Farley Nuclear Plant
C. Hillman, Security Manager
R. Johnson, Instrumentation and Controls Superintendent
J. Kale, Maintenance Engineering Support Group Supervisor
M. Mitchell, Health Physics Superintendent
R. Monk, Engineering Support Supervisor - Equipment Evaluation
*C. Nesbitt, Assistant General Manager - Plant Support
J. Odom, Superintendent Unit 1 Operations
*J. Powell, Superintendent Unit 2 Operations
*L. Riley, Performance Review Group Engineer - Engineering Support
*L. Stinson, Assistant General Manager - Plant Operations
*J. Thomas, Engineering Support Manager
R. Vanderbye, Emergency Preparedness Coordinator
W. Warren, Engineering Support Supervisor - Performance Review

*G. Waymire, Safety Audit and Engineering Review Site Supervisor
*L. Williams, Training/Emergency Preparedness Manager
*B. Yance, Plant Modifications and Maintenance Support Manager

*Attended the exit interview

During the course of this inspection a number of other licensee employees were contacted that work for HP, operations, technical, engineering, security, maintenance, I&C, and administrative departments.

2.0 PLANT OPERATIONS (40500, 71707, AND 92901)

The inspectors conducted frequent tours of the MCR to verify proper staffing, operator attentiveness, and adherence to approved procedures. The inspectors also reviewed operator logs and TS LCO tracking sheets, walked down the MCBs, and interviewed members of the operating shift crew to verify operational safety and compliance with TS. Instrument indications, trend charts and safety system lineups were periodically reviewed from control room indications to assess operability and plant conditions. The inspectors attended daily plant status meetings to maintain awareness of overall facility operations, maintenance activities and recent incidents. Morning reports and FNPIRs were reviewed on a routine basis to assure that potential safety concerns were properly reported and resolved.

During routine tours of the MCR, the inspectors regularly observed that very few MCB and EPB annunciators were in alarm at any one time for the entire control room. Of these, only one or two annunciators were in an alarm condition for any extended period. The EPB and Unit 1 MCB annunciators were frequently in a "blackboard" condition. The number of MCB deficiencies continued to remain very low, the aggregate number for the entire control room being about 15. MCB deficiencies continued to receive high level management attention and were pursued aggressively.

2.1 Status

Unit 1 operated continuously at full power for the entire inspection report period.

Unit 2 operated continuously at full power for the entire inspection report period, except for three ramp downs to accomplish maintenance on secondary systems. On January 22, 1996, the unit was ramped down to 65% power to replace a 2B SGFP governor valve control card. On January 23, unit power was reduced to 95% to replace an EHC servo-valve on the #1 governor valve for the high pressure turbine. On January 30, Unit 2 was ramped down to 15% power for three days to replace all SGFP and MTG EHC servo-valves, and to flush the SG's to reduce entrained sodium.

2.2 Routine Plant and Facility Tours

General tours of FNP facilities were performed to examine the physical conditions of plant equipment and structures, and to verify that safety systems were properly aligned and activities that effect their operability were performed IAW regulatory, operating license and plant procedural requirements. These tours were performed on both dayshift and backshifts.

Limited walkdowns of a more detailed nature of the accessible portions of safety-related structures, systems and components were also performed in the following specific areas:

a. SWIS
b. Unit 1 and 2 EDGs 1-2A, 1B, 2B, 1C and 2C
c. Unit 1 MDAFW pump rooms
d. Unit 1 and 2 piping penetration rooms (100 and 121 ft. elev.)
e. Unit 1 and 2 electrical penetration rooms (139 ft. elev.)
f. MCR HVAC and CREVS
g. Unit 1 and 2 Battery rooms
h. Unit 1 AFW pump rooms
i. Unit 1 and 2 SFP, heat exchanger, and pump rooms
j. Unit 1 PRF room
k. Unit 2 Containment Spray pump rooms
l. Turbine building
m. Primary Access Point
n. Unit 1 and 2 Containments
o. Unit 1 and 2 SGBD spaces
p. Auxiliary Building HVAC and Containment Purge rooms

In general, material conditions and housekeeping for both units were adequate. Cleanup of both units (especially Unit 1) following the completion of U1RF13 last November is essentially finished. However, plant physical appearances are not at the level they were early last summer prior to the INPO evaluation. Although, almost all plant areas were free of debris and abandoned tools/equipment, the level of cleanliness and physical conditions of many auxiliary building areas presented a well worn and used appearance. Stained floors, chipped paint, worn surfaces and reduced lighting dominated or impaired the appearance of many areas in the SWIS, Auxiliary, EDG and Turbine buildings. A number of minor equipment and housekeeping problems were reported to the responsible SS and/or maintenance management for resolution.

On January 30, Unit 2 was ramped down in power to approximately 15 percent for condenser water box inspections, sodium cleanup in the secondary, and some minor work in containment. That same day, a visiting Region II HP inspector and one of the resident inspectors made a Unit 2 containment entry along with a licensee HP technician and SFO. The inspectors toured most areas in containment, including those areas inside the bioshield wall on the 105 foot level. Piping and instrumentation were largely leak tight. Some minor dry boric acid

packing leaks were evident. Three check valves had some body to cap leakage; two were dry and one had some moisture in the boric acid powder. The licensee cleaned the boric acid off, observed the valve over the next day and did not see any further leakage. Three snubbers that exhibited slight weepage were examined closely and refilled, none of the three had drained below half full of its reservoir. The inspectors noted good pre-job planning (including ALARA considerations) for the maintenance activities observed in containment. The licensee's HP coverage during this tour was good.

In addition to general housekeeping, the inspectors continued to notice specific problems with plant lighting and water/moisture intrusion as described below:

Moisture in the Auxiliary Building

To follow up on observations made in IR 95-20 (paragraph 3.a.1), an inspector toured the auxiliary building on January 27. There had been a heavy rain the previous night. Moisture was again observed in the CCW room areas and around the AFW spaces. In the 2A DC switch gear room, droplets of moisture from the room cooler were blowing across the gear's top and impinging on the opposite wall. No moisture was observed falling on the gear. No equipment damage was evident at the time. Licensee ES personnel submitted REA 96-1093 requesting help from corporate engineering ventilation experts to evaluate the situation, including prior observations documented in IR 95-20 .

Plant Lighting in the RCA

During a routine tour of the Unit 1 RCA, an inspector noticed a large number of burned out ceiling lights (approximately 60 lights) on the floors between the 100 foot and 155 foot elevations. High traffic hallways were typically well lit, but many rooms had one or more of their lights out which for most rooms did not present a problem. But in a number of Unit 1 areas the lighting was considerably diminished (e.g., 1B SFP HX room, SGBD control panel spaces and radioactive equipment tool storage room on the 130 foot elevation, and various valve access compartments). This problem was previously discussed with plant management last inspection period (see IR 95-20), and considerable effort was expended at that time to relamp the Unit 1 and 2 RCA. However, many out of the way areas and rooms still have lighting deficiencies. Plant employees, system operators in particular, do not appear to be reporting burned out lights and taking advantage of the BULB relamping program. Management should ensure critical plant areas remain properly lit.

2.3 Plant Tagout Orders

During the course of routine inspections, portions of the following tag orders and associated equipment clearance tags were examined by the inspectors:

- TO# 95-3175-1; Auxiliary Fuel Oil Transfer Pump
- TO# 95-4037-1; RMWST Degas Catch Tank Pump
- TO# 94-0684-2; Waste Evaporator/CCW Systems
- TO# 94-2910-2; Containment Purge System
- TO# 96-0064-0; 1C EDG
- TO# 96-0154-1, Unit 1 TDAFW
- TO# 96-0084-1, 1B PRF

All tags and tag orders examined by the inspectors were properly implemented. Several components associated with tag orders 95-3175-1 and 95-4037-1 were located outside in the plant yard area. Although still legible, these tags had begun to deteriorate. Tag orders are audited monthly on a sampling basis to verify that affected systems remain properly aligned according to the applicable tag order and tags remain installed in place. However, it is possible that some old tag orders could remain in place for several months without reverification. The licensee advised the inspector that consideration would be given towards providing a different type tag for outdoor locations which would not be subject to deterioration from the weather.

2.4 Technical Specification Compliance

Inspectors reviewed selected TS LCO status sheets on a regular basis in order to confirm that entries into TS Action Statements were recognized, tracked, and complied with. Responsible Operations personnel, primarily the applicable unit SFO, maintained good control of all TS LCO requirements and Action statements, except for NI-32 and 36 on November 29 (see report section 2.9).

2.5 Engineered Safety Features Walkdown - Unit 1 Component Cooling Water System

The inspector performed a review and walkdown inspection of the accessible portions of the Unit 1 CCW System to verify system operability and to determine if the CCW system alignment procedures conformed to plant drawings and the as-built configuration.

The following documents were used for this evaluation and inspection:

- Drawing Nos. D-175002, Sheets 1 and 2, P & I Diagram - CCW System
- Drawing Nos. D-15023, Sheets 1 and 2, Process Flow Diagram - CCW System
- Document A-181000, Functional System Description - CCW System
- 1-SOP-23.0A, Unit 1 CCW System (Revision 2)
- 1-STP-23.7, Unit 1 CCW System Flow Path Verification Test (Revision 15)

The CCW system flow diagrams and flow path verification procedure for the principal valves, Procedure 1-STP-23.7, were reviewed and the valves included in the flow path verification procedure were found to be appropriate.

During the walkdown inspection of the Unit 1 CCW System, the inspector reviewed the following: alignment of electrical breakers to the CCW pumps and MOV valves and the accessible manual valves in the system; installation of hangers and supports; closure of drain and vent pipe valves and installation of pipe caps; labeling and identification of pumps, valves and components; and lubrication levels in all visible oil and lubrication devices. The CCW piping system was inspected to determine if there was any unidentified leakage in the system. The housekeeping in the areas of the various CCW components was inspected to determine if transient combustibles were properly controlled.

In general, the equipment condition of the CCW system components was satisfactory. No major leaks were identified. However, several minor leaks were noted. These had been previously identified by the licensee and work requests had been issued for correction. The housekeeping in the CCW System areas inspected was found satisfactory and no transient combustibles were noted. Several minor discrepancies were identified during the walkdown inspection of the CCW System. These items included: an inoperable valve position indicator on one valve; one valve in the correct alignment but not sealed in the correct position as required by the procedure; a missing valve position indicator for one MOV valve; and an incorrect building location indication in the procedure for one valve. These minor items did not affect the operability of the system and were discussed with the unit SS. The SS initiated appropriate action to correct these items.

The calibration of the suction and pressure instrumentation for the CCW System pumps was reviewed and found to be current. These instruments were included in the licensee's routine calibration program. A number of the CCW System instrumentation devices such as the pressure instrumentation at the CCW System heat exchangers were not in the licensee's calibration program. The licensee stated that this instrumentation was not used to perform surveillance testing and, therefore these devices did not need to be included in the plant's calibration program.

The inspector reviewed Procedure 1-M-046, Second 10 Year IST Plan, and noted that some of the pressure relief valves for the CCW system were not included in the IST Program. These included pressure relief valves Q1P17V0006A, Q1P17V0006B and Q1P17V0006C which are installed on the CCW shell side of the CCW heat exchangers. The licensee's current IST Program does not consider these valves to be safety related since their function is to provide component or piping protection from thermal expansion. However, the licensee informed the inspector that an evaluation was in process for including these valves in the Third 10 Year IST Plan which is due to begin in 1997.

Based on this evaluation, the Unit 1 CCW System was operable and satisfactorily maintained.

2.6 Unit 2 Ramp Down Due a Steam Generator Feed Pump Control Card Failure

On January 22 at 8:37 p.m. with Unit 2 at 100 percent power, a non-licensed operator noticed that the LP governor valve on the 2B SGFP was oscillating in stroke. The valve which normally has an approximate zero to 1/8 inch control dead band movement, had an approximately 3 inch oscillation. The SO reported this to the control room who could see a 20 rpm swing (non-obvious motion, slightly greater than normal) on the speed indicating gage. The pump began to lose speed and operator action could not prevent this. Power was reduced such that the failing SGFP could be taken off service (9:11 p.m.). It resulted in a approximate 1 MW per minute ramp down in power and all other support equipment was reported to operate properly. With the plant stable at 64 percent power, the 2A pump was shut down. Later, the inspectors reviewed the data on the ramp down.

I&C personnel found that the 2B SGFP had a control card failure. The speed control card was replaced and tested early (01:27 a.m.) on the January 23rd. Power ascension was resumed at 03:48 a.m. on the same day but was halted due to turbine valve problems (see below). The removed card which had been replaced in October 1995 was sent to the card vendor for evaluation (Material Requisition 95-001666). FNPIR 2-96-023 was initiated by the licensee. An inspector observed a portion of the ramp up process and the satisfactory 2B SGFP operation.

2.7 Unit 2 Number 1 Governor Valve Motion Problem

On January 23, while returning to power operation after a ramp down, Unit 2 personnel found that the turbine governor valve control switched from automatic control to a hold position - single valve control (DR 538669). Once in the hold position, the turbine was still controllable in manual with the number 1 governor appearing to move slow but controllably. Inve tigation revealed that the number one governor valve was lagging behind its program position causing the program to default to a hold condition. In the discovery period, several checks were made on the valve and its controls. The Moog servo-valve that controls the governor valve's position was replaced and, subsequently, the valve and its control system tested satisfactorily. The inspector observed the discovery period checks and the functional testing of the replacement valve.

Based on the servo valve failure and past EHC system problems of June 1995, the licensee sent the removed number 1 valve to the valve vendor for evaluation. The vendor provided a verbal and written report. The inspector reviewed the written report, examined a removed valve's internal filter, and observed several replacement valve installations (see paragraph 2.8). From this recent problem, the number 1 valve was found to have a partially plugged internal filter and some worn parts. The plugging by itself could have caused the governor valve control

problem. The number 1 valve had been replaced in June, 1995. The licensee was continuing to investigate but as a interim measure replaced all servo valves on the Unit 2 main turbine and two main feed pumps during the January 30 down power. These valves will be sent to the valve vendor for evaluation. To date, the licensee has made a good effort to resolve at least this portion of EHC system problems.

2.8 Unit 2 Ramp Down for Scheduled Work

On January 30, Unit 2 was ramped down from 100% to 15% power for scheduled maintenance. The licensee experienced no major problems during the down power. While at 15 percent power, the licensee inspected and cleaned two main condenser water boxes, replaced MTG and SGFP Moog servo-valves (see above), and performed minor repairs in containment. The licensee removed by flushing approximately 2 grams of sodium per SG while at the reduced power. While at full power, chemicals that can cause SG damage, primarily sodium, is mainly located in crevices of the condensate, feedwater, and SG components. At lower power, the sodium returns to solution and is thus available for removal. During the tube inspections in the condenser water boxes, the licensee plugged four tubes that had exhibited denting but had no through wall leaks. The inspectors observed portions of the down power, portions of the water box inspections, and toured containment. No significant findings were identified.

On February 1, the licensee secured the 2A SGFP after finding a dripping EHC fluid leak at a recently replaced low pressure servo valve. The pump had been running 20 minutes when the small leak was observed by an on-station non-licensed operator. Upon servo removal, the license found that one of the "O" rings that seals the valve to its piping had a defect. The "O"ring was to be sent back to the valve vendor who had provided the "O"ring with the valve. The inspector performed the following: examined the failed "O"ring; observed other new "O"ring installation points; observed 2A SGFP operation from the control room during its re-start and during paralleling with the operational 2B SGFP; and, then observed it insitu in the turbine building - the pump behaved as expected. Of the 10 servo valves replaced, only one valve had a problem and that was not due to the installation activity itself.

On February 1, the inspectors observed significant portions of the Unit 2 ramp up to 100 percent power, including startup and return to service of the 2B SGFP, IAW SOP-21.0, "Condensate and Feedwater System," UOP-3.1, "Power Operation," SOP-28.1, "Turbine Generator Operation." The return to full power was accomplished without incident. Operator actions were smooth, deliberate, and consistent with procedural requirements. They were extremely cautious and attentive to all details of the changing conditions. Plant equipment performed as expected.

2.9 Unit 2 Entry Into A Specified Condition Not Allowed By Technical Specifications

On November 28, 1995, Unit 2 tripped from 100% power (see IR 50-364/95-20, paragraph 3.a.4). On the following day, I&C replaced a faulty NIS intermediate range detector (NI-36); however, they inadvertently left the detector disconnected. Unit 2 reached Mode 2 before operators determined that NI-36 was not responding. This resulted in a violation of TS requirements (see IR 50-364/95-20 paragraph 4.b.3). The licensee initiated a root cause investigation and issued LER 50-364/95-09 dated December 19, 1995. An inspector reviewed the LER, root cause summary report, operator logs, and associated FNPIR 2-95-335. Based on this information, and interviews with the Unit 2 Operations Superintendent and one of the responsible SS's, the inspector concluded that Operations and the root cause team failed to recognize all of the TS operability requirements that affected NI-36. Furthermore, Operations failed to recognize that the other NIS intermediate range channel (NI-35) and an NIS source range channel (NI-32) had potentially entered a condition not allowed by TS.

Further investigation by the licensee and the inspector, confirmed that NI-36 had violated TS requirements as soon as it entered the asterisk ("*") condition specified by Table 3.3-1 (i.e., fuel in the vessel, reactor trip breakers closed and control rods capable of withdrawal). The LER assumed that NI-36 was not required to be operable until the unit entered Mode 2. The licensee has since concurred with the inspector and was in the process of issuing a LER revision.

In addition to NI-36, the inspector questioned Operations management on whether NI-32 and NI-36 had also violated TS by entering the specified asterisk condition before TS required channel functional testing was completed and functionally accepted. According to step 3.26 under the "Precautions and Limitations" for FNP-2-UOP-1.3, "Startup Of Unit Following An At Power Reactor Trip," reactor trip breakers should remain open, or the CRDM MG Sets should remain de-energized, until SSPS operability testing, and source range and intermediate range channel functional tests, were completed. Step 3.26 specifically referenced the surveillance requirements of TS Table 4.3.1.1 and stated that the applicable Mode was the asterisk condition. The inspector's review of operator logs and interview with a Unit 2 SS, appeared to indicate that the asterisk condition was entered before the functional testing of NI-35 and NI-32, and operability testing of SSPS, were completed.

Further investigation by the licensee confirmed that Operations had failed to comply with step 3.26 of UOP-1.3. The Unit 2 CRDM MG sets were running and the reactor trip breakers were closed before required testing was completed. However, the licensee subsequently determined that the "Rod Control Startup Reset Switch" on the MCB was not reset until just before rods were withdrawn for entering Mode 2. Until this switch was reset, control rods could not be withdrawn. And, although Step 3.26 does not recognize this switch, and Operations failed to fully understand the TS surveillance requirements of the asterisk condition, the TS were being met (unbeknownst to the operating crews) by the reset switch. When the reset switch was actually reset, all required testing was completed except that NI-32 had not been functionally accepted.

Technically, NI-32 was functionally accepted and declared operable the same time NI-36 was. However, additional inquiries by the inspector revealed that no LCO status sheet was ever issued for NI-32. This was another Operations oversight in that NI-32 was not declared inoperable when it was disconnected to facilitate replacement of the NI-36 detector. Section 6.5 of FNP-0-AP-16, "Conduct Of Operation - Operations Group," would have clearly required a LCO status sheet to ensure TS requirements were tracked and fulfilled.

A separate FNPIR 2-96-025 was initiated to address the inspector's concerns regarding entry into the specified asterisk condition prior to completing required surveillance testing. Another root cause team was assembled to investigate the additional issues. Although the initial investigation lacked sufficient thoroughness, the current investigation and root cause efforts appear very comprehensive and thorough. A broad range of corrective actions have been developed, some have already been implemented and others are still being planned.

TS 6.8.1 requires certain written procedures, which include the general plant operating procedures and administrative procedures recommended in Appendix A of RG 1.33, to be established and implemented. Failure to comply with UOP-1.3 and AP-16 constituted a violation of TS 6.8.1. However, due to the low safety significance and comprehensive licensee corrective actions this violation will not be subject to enforcement action since it meets the criteria specified in Section VII.B of the NRC Enforcement Policy. This item was identified as NCV 50-364/95-21-01, Inadequate Control Of TS Requirements For The Specified asterisk Condition.

2.10 Effectiveness of Licensee Control in Identifying, Resolving, and Preventing Problems

The inspectors routinely reviewed all FNPIRs initiated during the inspection period to ensure that plant incidents that effect or could potentially effect safety were properly documented and processed IAW FNP-0-AP-30, "Preparation and Processing of Incident Reports ...". The inspectors also reviewed a number of completed FNPIRs to determine licensee's effectiveness in: 1) identifying/describing problems; 2) elevating problems to the proper level of management; 3) conducting problem/root-cause analysis and/or derivation; 4) assessing operability and reportability; 5) developing appropriate corrective actions and 6) evaluating cause/corrective action scope for generic implications. The following is a list of the completed FNPIRs specifically reviewed by the inspectors:

- FNPIR 1-95-048; Loss of Cooling to #3 Main Power Transformer
- FNPIR 2-95-189; TDAFW Pump Failed to Meet Acceptance Criteria for Speed
- FNPIR 1-95-122; Service Air Dryer Breaker Found Closed With Red Tag
- FNPIR 2-95-206; Missed Firewatch

- FNPIR 1-95-263; Shoe Horn Snagged on Fuel Assembly
- FNPIR 2-95-290; 2B EDG and 2B RHR Tagged Out Simultaneously
- FNPIR 1-95-208; MCR Pressurization System Humidistats Not Calibrated

- FNPIR 1-95-245; A Train MCR HVAC Tripped on Low Oil Pressure
- FNPIR 1-95-336; Welding Without Approved Open Flame Permit
- FNPIR 1-95-298; 2B PAHA Transducer Failure
- FNPIR 1-95-273; 1D Containment Cooler Fast Speed Breaker Tripped

Overall, the inspectors concluded the licensee's program for identifying and resolving problems was effective, and being accomplished IAW AP-30. Plant personnel exhibited an appropriate threshold for identifying problems and initiating FNPIRs. Each new FNPIR initially received prompt attention and was routinely discussed by management in the next morning status/POD meeting. In the examples listed above, resolution of identified problems by "direct derivation" were assigned to knowledgeable individuals of the responsible organization. Their proposed corrective actions appeared appropriate and comprehensive, with one exception. FNPIR 1-95-263 failed to document resolution of the piece of heat shrink tubing left in the reactor vessel. After being notified, the licessee attached a written safety evaluation to the FNPIR. Generic implications and previous histories of similar problems were regularly considered. However, timely completion of incident reports still remains a challenge. Processing a plant incident report typically takes two or more months. Additional management attention in this area should be considered.

2.11 Institute of Nuclear Power Operations Evaluation Report

INPO conducted a comprehensive evaluation of FNP during the weeks of July 10 and 17, 1995. An inspector reviewed the final report issued in November 1995 and concluded that INPO did not identify any important safety issues that required NRC Region II followup action. Furthermore, none of the INPO findings warranted a significant reassessment of NRC perspectives on licensee performance.

2.12 Operations Followup

a. (Closed) VIO 348/95-16-01, Improperly Installed Scaffolds Over Safety-Related Equipment.

The licensee responded to this violation by letter dated November 13, 1995. An inspector reviewed this letter, the applicable FNPIR (1-95-223), and revised FNP-0-GMP-60, General Guidelines and Precautions for Erecting Scaffolding (Revision 15). The inspector noted that GMP-60 had been revised to provide additional guidance in the evaluation, approval, erection and review of scaffolding prior to use. Training records were reviewed by the inspector and these records indicated that craft personnel responsible for the erection of scaffolding and personnel responsible for the review of erected scaffolding had been trained in the requirements of the procedure.

In addition, a task force had been formed to reevaluate the existing program and provide additional enhancements in the administrative control for the erection of scaffolding in the vicinity of safety related equipment. The inspector verfied completion of all licensee corrective actions. This item is closed.

b. (Closed) URI 50-348, 364/95-14-01, High Containment Air Temperature

During the end of July 1995 and early August an inspector expressed concern that Unit 1 and 2 containment air temperatures were closely approaching and possibly above the TS 3.6.1.5 limit of 120 degrees Fahrenheit. Furthermore, the inspector questioned the methodology used by Operations for monitoring containment temperatures. The inspector's concerns were detailed in NRC IR 50-348, 364/95-14 dated September 6, 1995. The licensee responded to these concerns by letter dated November 2, 1995. Based on a review of the SNC response and discussions with NRR, the inspector concludes that FNP currently meets applicable TS requirements and there does not appear to be a significant safety issue. Since there is no significant safety issues associated with this activity, the NRC does not consider further review of this issue to be necessary at this time. This URI is closed.

c. (Closed) URI 50-364/95-20-04, Mode Change With Inoperable Source Range Detector (NI-32)

This URI is closed based on the issuance of NCV 50-364/95-21-01 (see section 2.9).

3.0 MAINTENANCE AND SURVEILLANCE (62703, 61726, AND 92902)

Inspectors observed and reviewed portions of various licensee corrective and preventative maintenance activities, to determine conformance with procedures, work instructions and regulatory requirements. Work orders were also evaluated to determine status of outstanding jobs and to ensure that proper priority was assigned to safety-related equipment. Inspectors witnessed surveillance activities performed on safety-related systems/components in order to verify that activities were performed IAW licensee procedures, FNP Technical Specifications and NRC regulatory requirements. Portions of the following maintenance activities and surveillance tests were observed:

3.1 WO 00530237; Water Leaking From The Casing Vent Piping Of Motor Driven Auxiliary Feedwater Pump 1A

An inspector walked down and examined completed corrective mechanical maintenance performed to repair the piping leaks of Unit 1 MDAFW Pump 1A. The completed work order and attached photograph of the fixed piping leaks were also reviewed to identify the completed work and materials used. Thread sealant was placed on the threads at the connection points to repair the leaks. All work examined was accomplished in a satisfactory manner.

3.2 WO 44881; Inspect And Clean, Megger The Motor For Motor Driven Auxiliary Feedwater Pump 1A Motor

An inspector observed electricians perform preventive maintenance by meggering MDAFW Pump 1A motor IAW FNP-0-EMP-1701.01, Electrical Equipment Condition Testing. The meggering was conducted in the switchgear room. MDAFW 1A Motor Breaker DF-10 was removed from its cubicle and a blank test breaker was inserted for the test connection for the motor and associated cables. All work observed was accomplished as required by the procedure in a satisfactory manner.

3.3 WO 533289; Correct Problems In Unit 1 Seismic Monitoring System Identified In Deficiency Report 533289

An inspector observed I&C technicians troubleshoot and determine that a defective lamp holder was causing an intermittent short circuit. The lamp holder was used as a fuse holder and was mounted on a printed circuit card. After the defective card was replaced, the technicians perform a system software test to verify the problem was corrected. All troubleshooting and work observed was accomplished in a logical and satisfactory manner.

3.4 WO 538669; Replace Turbine Generator Moog Valve

An inspector observed I&C technicians replace a Unit 2 turbine generator EHC servo-valve. The work was accomplished using FNP-0-IMP-247.1, Moog Valve Installation Models 72103 And 760A185. After the replacement was completed, the inspector monitored the Unit 2 turbine generator to verify it was operating properly.

3.5 WO 448055; Correct Problems In Instrument Loop 1085 Identified In Deficiency Report 538002

An inspector observed I&C technicians calibrate Instrument Flow Loop 1085 using procedure FNP-2-STP-224.1, Waste Monitor Pumps No. 1 And 2 Flow N2G21FT1085A And N2G21FT1085B Loop Calibration. The calibration was being performed in a satisfactory manner.

3.6 WO 68584; Change Overload Heaters To T38 And Verify Overload Adjustment Knob Setting

An inspector observed electricians change the overload heaters and perform post maintenance testing on a Unit 2 AFW pump room sump pump motor. The work and testing were performed using FNP-0-EMP-1513.01, ITE Magnetic Starters And Overloads Relays, in a satisfactory manner.

3.7 WO 535141; 2B CRDM MG Set Motor Replacement

An inspector observed portions of a motor replacement and subsequent return to service of the 2B CRDM MG set. The motor had been identified to have higher that expected vibrations with an upward trend. The motor

was replaced prior to any evidence of failure. Post repair maintenance testing and operational re-energization was satisfactory.

3.8 WO 5363341; 1C EDG High Crank Case Trip

On January 8, during a routine surveillance test of the 1C EDG, the EDG tripped. The first out annunciator indicated high crank case pressure as the cause. (The high crank case pressure trip is blocked when a SI signal is present). The WO listed above was used to troubleshoot the crank case trip pressure switch. This switch proved to be operating properly - an inspector observed part of the functional testing of the switch. A second WO 506953 was issued to investigate an internal orifice that meters crank case vacuum. This was also observed by the inspectors and was not identified as a problem. The licensee has initiated FNPIR 1-96-003 and contacted the EDG vendor. With the other EDG's operable, TS allowed the 1C EDG to be inoperable for 10 days.

With a resident in attendance, the 1C EDG was run again without a problem on January 9. The EDG was then secured and re-started later that evening when it tripped again on high crank case pressure. The licensee requested onsite support from the vendor technical representative and corporate engineering.

Problems with higher than normal crank case pressures were also experienced by Plant Hatch, which has similar EDG's (see IR 50-321, 366/94-28, 95-08, and 95-14). Cooling water from within the lube oil heat exchanger had leaked into the lube oil. The water, on the order of as few as 2 ounces, had then been pumped through normal lube oil passages and impinged on the under side of the piston heads and vaporized. The rapid expansion of the vapor caused a pressure spike causing a Hatch EDG to trip. The inspector talked with a resident inspector at Hatch and reviewed their inspection reports on the topic. Initial gross sampling of the Farley 1C EDG oil indicated no water. Other samples were sent to a separate, special vendor lab. Results from that lab received on January 11, indicated 0.08 % water per ml (minimum detectable being 0.05 %). This sample was taken with the engine secured via the oil dip stick hole. However, once the 1C EDG valve cover was removed, the interior cover oil coat exhibited some emulsification from entrained moisture. The oil contents of the EDG were drained, mixed, and sampled - the results of that sample indicated 0.5 % water which exceeded the vendor TM recommended value of 0.3 %. Later, it was determined that the barrels used to collect the drained oil had been contaminated with water and the higher value was questionable. The 1C EDG was refilled with new oil. The licensee is continuing to evaluate the conditions surrounding the high crank case trips and acceptability of current practices for conducting routine EDG oil samples. The EDG vendor indicated that Farley and Hatch were the first and only nuclear diesel purchasers to have water intrusion problems. The resident inspectors will followup on the licensee's final root cause report. Additional efforts to repair the 1C EDG and return it to service are described below.

3.9 WO 73907; (TYP) 1C EDG Investigation

With a vendor and corporate technical representatives supporting the site personnel on January 10 through 14, the 1C EDG was evaluated for problems that could have caused the above problems. The following components were checked:

- Cylinder pressure checks indicated two weak cylinder sets. Those cylinders sets were pulled and replaced. Examination of the rings did not indicate they were a true source of the problem. The licensee performed liquid penetrant examinations of the removed pistons with no positive indications. The pistons were sent to the vendor for further examination. An inspector was present for the ring and piston examinations.

- An inplace check of the EDG's super charger oil seals was performed. No problems were identified. However, for an optimum seal inspection the super charger should have been removed. An inspector reviewed the results of the check and discussed them with corporate engineering.

- The lube oil heat exchanger was disassembled and leak tested. Due to a slight, but significant leakage, one tube was plugged. The inspector observed portions of the inspection and final pressure testing. It was this leak that most likely caused the intrusion of water into the crank case.

The 1C EDG was reassembled and tested. Several maintenance starts and inspections were performed to ensure proper diesel operation. The diesel was then run for 24 hours to break-in the new rings. Operations conducted a post-maintenance surveillance test and the 1C EDG was functionally accepted and declared operable on January 14, 1996. The inspectors observed various phases of the testing and inspections, and found them acceptable.

3.10 WO 567871; 1C EDG Annunciation Problems (Speed Signal Generator)

Following its return to service, on January 18, about one hour after it was shutdown, annunciator 56 at the diesel's local control panel came into alarm and then cleared, twice. The licensee immediately generated WO 567871, entered the TS LCO action statement, and performed 1-STP-27.1 and 2-STP-27.1 (AC Source Verification). An inspector discussed aspects of the alarm problem with the licensee. On January 21, the licensee discovered that a wire within the signal generator unit (a lead to the amphenol plug) had broken. The wire was repaired and the 1C EDG was retested to verify operability. While the alarm was in (i.e., the wire not connected to the amphenol plug), the 1C EDG would not have started on a SI signal. The licensee initiated FNPIR 1-96-020, which the inspectors will review when it is completed. The repair was effective. The licensee is still considering potential inspections of the signal generators for the other diesels in the near future.

3.11 FNP-2-STP-912.0 and 913.0; Reactor Coolant Pump 4160 Volt Bus Reactor Trip Undervoltage and Underfrequency Relay Tests

EM personnel calibrated the reactor coolant pump bus undervoltage and underfrequency relays. An inspector observed the electricians perform the calibrations and conduct the tests as required by STP-912 and 913 for 4160 Volt Bus 2B undervoltage and underfrequency relays (DB02271, DB02273, DB02811, and DB02812) and Bus 2C undervoltage relays (DC02271 and DC02273). The inspector verified that the calibrations and tests were satisfactorily performed and the data observed was within the TS requirements. The licensee personnel conducted the calibrations and tests as required by procedure in a competent manner.

3.12 FNP-2-STP-227.11; Radiation Monitor Q2D11RE0025A Spent Fuel Pool Ventilation Isolation Calibration And Functional Test

I&C technicians performed surveillance testing on radiation monitoring equipment using work order WO 448086. An inspector observed the I&C technicians perform the calibrations and tests as required by the work order. The inspector verified that the calibrations and data were within the "Acceptance Criteria" of the surveillance procedure. The I&C technicians performed the surveillance in a competent manner.

3.13 FNP-1-STP-23.3; Component Cooling Water 1C Inservice Test

After performance of a lubrication PM, the above surveillance was satisfactorily performed. The inspector independently checked many of the pump parameters and observed the RO perform the vibration testing and found them satisfactory.

3.14 FNP-1-STP-80.1; EDG 1B Operability Test

When the 1C EDG was found to have problems requiring it to be taken out-of-service (see section 3.8 of this report), an operability test run of the 1B EDG was satisfactorily performed on January 10. The inspector observed the start and timing of the start from the control room. The engine came up to speed in less that 10 seconds and all parameters were normal. A walkdown of the running EDG indicated no problems.

3.15 FNP-2-STP-80.1; 2B Operability Test

On January 10, an operability test run of the 2B EDG was performed for the same reasons as above. An inspector observed the satisfactory start from the control room and then performed a walkdown of the running diesel. All indications were normal on the unit.

3.16 FNP-1-STP-11.2; 1B Residual Heat Removal Pump Quarterly Inservice Test

An inspector observed the satisfactory performance of the 1B RHR pump quarterly IST from the MCR. The RO at the controls communicated well with the RO performing the test at the pump. All controls operated appropriately during the test. Operators satisfactorily returned the system to a non-test lineup.

3.17 Refueling Outage Overtime

During unit refueling outages, plant maintenance (i.e., MM, EM, and I&C) personnel are routinely scheduled to work six 12 hour days a week. The last Unit 1 (U1RF13) and Unit 2 (U2RF10) refueling outages were no exceptions. Maintenance personnel routinely worked the same shift (days or night) until about half way through the outage then all the maintenance crews switch to the other shift. It was during this switch that a large number of maintenance personnel worked a seventh 12 hour shift within in a period of seven consecutive 24 hour days. (Note, during a refueling outage, day shift runs from 7 a.m. to 7 p.m., and night shift runs from 7 p.m. to 7 a.m.).

TS Section 6.2.2.f.3 and Section 3.3.3 of AP-64, "Work Schedules For Personnel Performing Safety-Related Functions," limits the working hours of key maintenance personnel who perform safety-related work to 72 hours in seven days. Deviating from this requirement is allowed by TS Section 6.2.2.f.5 and Section 3.4.2 of AP-64 only as long as it is reviewed and approved by the Maintenance Manager or his designee (group supervisor). After reviewing the daily shift time and work status logs of several selected I&C maintenance crews, the inspector determined that the technicians on crews 2B and 4B had worked seven 12 hour shifts between September 30, 1995 and October 10. During this time, both crews switched from day shift to night shift with only 24 hours of scheduled off-time in-between the two weeks. The net result was that the I&C technicians on both crews worked up to 84 hours in a seven day period beginning from 7 a.m. on the first day of their last week on day shift until the 7 a.m. after their first night shift. The inspector requested maintenance management to investigate this problem and determine if any other crews were subjected to similar excessive work hours without management's knowledge.

Subsequent investigation efforts by the Maintenance Department determined that a significant number of maintenance personnel had worked seven 12 hour shifts in seven days during the shift change of the last two refueling outages. More specifically, during U2RF10 - 5 MM, 10 EM, and 8 I&C personnel exceeded the seven day overtime guideline; and during U1RF13 - 1 MM, 15 EM, and 18 I&C personnel exceeded it. Daily time sheets for prior refueling outages were not examined. Maintenance management acknowledged that the scheduling practice which led to this problem has existed for quite some time. Based on interviews with Maintenance Department management, supervision and timekeepers, and reviews of time sheets and outage schedules, the inspector concluded that this problem was unintentional. Although Maintenance Department

management and supervision were well versed in the overtime guidelines of TS and AP-64, and demonstrated efforts to comply with them, they failed to recognize the need for scheduling sufficient off-time between shift changes. This oversight resulted in approximately 60 unanticipated instances of maintenance personnel working more than 72 hours in seven days which is identified as a violation of the requirements in TS Section 6.2.2.f, and will be identified as VIO 50-348, 364/95-21-02, Excessive Maintenance Overtime During Refueling Outages.

3.18 Followup Maintenance/Surveillance

a. (Closed) VIO 50-348, 364/95-18-01, Inoperable Control Room Pressurization Unit Humidistats; and LER 50-348/95-007, Control Room Pressurization Unit Moisture Controllers

The LCO for TS 3.7.7 requires that two independent control room emergency air cleanup systems shall be operable. However, the licensee confirmed on September 8 and 26, 1995, that the charcoal filter heater humidity controllers for the A and B trains, respectively, of the control room pressurization units were inoperable and had been for an indeterminate period of time. In addition, the licensee identified that the humidistats were not in any preventive maintenance or surveillance test program.

The inspector verified the licensee implemented corrective action by reviewing the completed work orders and conducting a walkdown inspection of the equipment to examine the calibration label. Work orders WO 75571 and WO 75572 were implemented for both trains A and B that replaced both the humidity controllers and probes. In addition, both humidity controllers were placed into the Preventive Maintenance Task Program. The inspector concluded that corrective actions were implemented in a satisfactory manner. This VIO and LER are closed.

b. (Closed) IFI 50-348, 364/94-21-02, General Electric HEA Lockout Relay Failure

Per licensee testing and documentation this particular relay failure and implications were well understood and tracked. Corporate engineering response to REA 94-0630 dated September 12, 1995 (NMS letter #95-0091), recommended that all HEA lock out relays be physically tested and be retested every six years. The licensee is well into this test program and has plans to be through the first test cycle by the end of the next Unit 1 refueling outage in 1997 (i.e., U1RF14). The inspector has observed many of the relays being tested and discussed the schedule with the licensee's relay group. This IFI is closed.

c. (Closed) IFI 50-348,364/95-03-01, Service Water System Room Temperature Control

SWS Room temperature control values are listed in procedure FNP-0-STP-63.1. The rooms in the SWIS were generally observed to be maintained at the values listed. These values were also consistent with values listed in Section 9.4.5 of the FSAR. Limited exceptions have been noted when room temperatures have been increased for personnel comfort, but did not exceed electrical load values used in design calculations. The licensee maintained calibration control and set position control of the thermostats in the SWS. The batteries located in the SWS are maintained by a continuously available charger. The charger should maintain the availability of the batteries at the room temperature set point. Breaker TM U176271 for the 4160 Volt switch gear in the SWS did not establish any particular temperature warnings or restrictions. Room temperatures were set as required to maintain equipment conditions. This IFI is closed.

4.0 ENGINEERING AND TECHNICAL SUPPORT (37551 AND 92903)

Inspectors periodically inspected onsite engineering/technical support activities (e.g., design control, configuration management, system performance monitoring, plant modification, etc.). Effectiveness of on-site engineering and technical group support of licensee efforts to identify, resolve and prevent incidents or problems were also inspected.

4.1 Configuration Control Board Meeting

On January 3, an inspector attended a routine bimonthly CCB meeting. One primary purpose of the CCB is to screen any new ideas submitted as potential plant modifications. Proposed design changes are then evaluated and prioritized to ensure site resources are effectively utilized. The CCB meeting was well attended by plant personnel to support CCB deliberations and inquiries, and as champions for their specific idea/DCR. On the CCB itself were managers, or suitable designees from every major plant department, including responsible Corporate organizations. The meeting was chaired by the AGM for Plant Support, along with a Vice Chairman (the PMD Manager). A considerable number of DCRs and new ideas were presented to and dispositioned by the CCB. Overall the meeting was orderly and productive. Ever since its inception in November 1993, the CCB process has dramatically reduced and recently eliminated the backlog of old DCRs. Furthermore, it continues to maintain the level of new ideas and unscheduled DCRs at very low and manageable levels. The total DCN backlog of scheduled design changes continues to trend downward, and during 1995 was reduced by half.

4.2 Generic Letter 89-10 Open Item Followup Inspection

NRC IR 50-348, 364/94-28 identified twelve IFI's (94-28-01 through 12) and stated that resolution of the first nine items would be necessary for completing the NRC review of GL 89-10 implementation. The licensee responded to these nine items in a letter dated March 3, 1995, and provided actions and schedules for their resolution. The NRC reviewed the response and, in a letter dated November 9, 1995, indicated that the

proposed actions and schedules were acceptable. Based on the licensee's response, the NRC review of GL 89-10 for Farley was considered closed.

This inspection examined the licensee's completion of the actions to resolve IFI's 94-28-01 through 09, as well as IFI's 10 through 12. The status and findings for each item are described in Section 4.3.

4.3 Engineering Followup

a. (Open) IFI's 50-348, 364/94-28-01 through 03, Evaluate Settings of MOV's

These three IFI's involve the licensee's planned evaluations of MOV settings using criteria developed by EPRI. The inspector was informed that the licensee had begun the evaluations but that they had not been completed. Additionally, NRR is reviewing and preparing a safety evaluation report of the criteria. Pending completion of these activities and review of the licensee's actions in a subsequent inspection, the three IFIs remain open. The licensee indicated that the MOV evaluations would be completed by April 1, 1996, and that any necessary changes to MOV settings would be made commensurate with valve safety significance. These IFI's remain open.

b. (Closed) IFI 50-348, 364/94-28-04, Resetting the Torque Switches of 30 MOV's to Higher Values

NRC IR 94-28 found that the methodology used in determining many MOV settings had been changed and that the licensee had not adjusted actuator settings to incorporate the resultant new thrust requirements. A specific concern was identified that 30 MOV's had thrust settings near or below the minimums determined by the new methodology. The licensee's letter of March 3, 1995, indicated that the 30 MOV's would be reset in accordance with a schedule based on safety significance. Priority 1 (highest safety significance) MOV's would be reset during the 1995 refueling outages for each unit and priority 2 and 3 valves would be reset during the next two refueling outages (U2RF11 and U1RF14).

An inspector reviewed documentation which demonstrated that the licensee was retesting and attempting to reset the MOV's as stated in their letter. He also noted that the licensee had added 5% safety margin to the new settings. Fifteen of the 30 MOV's to be reset were identified as priority 1 and the inspector verified that Work Authorization Packages to reset/retest each had been completed during the licensee's 1995 refueling outages. Additionally, the inspector reviewed correspondence dated January 10 and 12, 1996, documenting requests to include the remaining 15 MOV's in the next Unit 2 and Unit 1 outages.

While the licensee was attempting to reset the MOV's in accordance with the new requirements, the inspector found that they were often unsuccessful. The new setting requirements were not achieved for 10

of the 15 MOV's that the licensee had attempted to reset. This was because of weak link and setting accuracy limitations. Where the new setting limits were not met, engineering evaluations were completed to establish the adequacies of settings used. The inspector reviewed the logic which the licensee applied in the evaluations and found the capabilities of the MOV's to perform their design-basis functions at the as-left settings was satisfactorily supported. Based on this, the inspector concluded that there was no safety concern that justified further NRC followup.

While there was no significant safety concern, the licensee's inability to achieve so many of the calculated settings suggested a weakness in their approach. The licensee provided a preliminary report of a recent licensee audit (95-SAER/21-7) as evidence that this problem was recognized and would be addressed. The inspector confirmed that the report documented concern that many settings were not being achieved, necessitating performance of individual MOV capability evaluations. The licensee stated that planned MOV modifications and replacements would increase the number of MOV's that could be reset to the new requirements but acknowledged that many MOV's still would not be able to achieve the new settings. This IFI is closed.

c. (Closed) IFI 50-348, 364/94-28-05, Updating Setpoint Documents

The new setpoint determination methodology referred to in the previous paragraph had determined minimum thrust setting requirements that were higher than those specified by the licensee's setpoint documents for 123 MOV's. NRC inspectors opened this IFI to verify that the licensee's setpoint documents were revised to update the settings specified for these MOV's. In a March 3, 1995 letter, the licensee stated that their setpoint documents would be updated prior to the next Unit 1 and 2 refueling outages (i.e., U1RF13 and U2RF10).

The inspector reviewed the licensee's field setpoint documents (B175804, Rev. 8 and B205804, Rev. 11) to determine whether they incorporated the new, higher requirements specified by the current engineering design basis documents (U418109, Rev. A and U418110, Rev. C). A sample of 42 MOV's were checked by the inspector and all setpoints had been correctly updated. This IFI is closed.

d. (Closed) IFI 50-348, 364/94-28-06, Replacement of Reduced-Voltage Outputs Provided by Westinghouse

NRC inspectors questioned the licensee's use of Westinghouse-supplied information in establishing reduced-voltage thrust output capabilities for certain MOV's. Of specific concern was its application for 44 MOV's which had setpoint reduced-voltage values greater than would be predicted by the current Farley methodology. The licensee stated that reliance on the Westinghouse information was to be eliminated. This IFI was opened to verify that the licensee's setpoint documents were revised to eliminate use of the Westinghouse-

supplied values. In their March 3, 1995 letter, the licensee indicated that the revision would be completed prior to the next Unit 1 and 2 refueling outages (i.e., U1RF13 and U2RF10).

The inspector reviewed the licensee's setpoint documents (B175804, Rev. 8; B205804, Rev. 11) to determine whether they had been revised and that they incorporated requirements that were consistent with the current engineering design basis documents (U418109, Rev. A and U418110, Rev. C). A sample of 11 of the 44 MOV's that were of concern were checked by the inspector, their setpoints were verified to be appropriately revised. This IFI is closed.

e. (Closed) IFI 50-348, 364/94-28-07, Updating of Reduced-Voltage Thrusts in Design Documents

The thrust requirements for 16 MOV's were greater than the reduced-voltage output thrust predicted by the Farley methodology. The inspectors did not identify any immediate operability concerns. The licensee stated that the thrust requirements and reduced-voltage output thrusts were being evaluated and that design documents would be revised based on the results of the evaluations. This IFI was opened to verify design documents were updated. In their March 3, 1995 letter, the licensee indicated that the revision would be completed prior to the next Unit 1 and 2 refueling outages (i.e., U1RF13 and U2RF10).

The inspector reviewed the licensee's design basis documents and verified that the revisions had been accomplished. Some MOV's still had setpoints that exceeded the determined reduced-voltage capabilities. Engineering evaluations were used to document the bases for their acceptability. The inspector reviewed the evaluations and found the logic used did demonstrate the acceptability of the setpoint values. This IFI is closed.

f. (Closed) IFI 50-348, 364/94-28-08, Periodic Verification of MOV Capabilities

This item identified a broad concern as to the adequacy of the methodology the licensee planned to use to determine and maintain an appropriate margin to account for potential age-related MOV degradation. After this item was identified the NRC determined that this issue should be addressed generically with all licensees. As noted in the NRC's November 9, 1995 letter to the licensee, this will be accomplished through issuance of an NRC generic letter addressing periodic verification of MOV capabilities. The issues identified to IFI 94-28-08 are to be resolved through the generic letter. This is IFI closed.

g. (Closed) IFI 50-348, 364/94-28-09, Periodic Verification of Capabilities of 1500# 10 and 14 Inch Copes-Vulcan Gate Valves

Like IFI 94-28-08, this IFI deals with a concern regarding the licensee's methodology for determining and maintaining an appropriate MOV capability margin to account for uncertainties such as potential age-related degradation. The two IFI's differ only in that IFI 94-28-08 focused broadly on all GL 89-10 valves while this IFI focused on specific MOV's. Similarly to IFI 92-28-08, this item will be addressed through an NRC generic letter on periodic verification of MOV capabilities. This IFI is closed.

h. (Closed) IFI 50-348, 364/94-28-10, Applicability of Industry Information to MOV Reduced-Voltage Output Determined by Farley Test

The licensee determined some of its MOV reduced-voltage outputs by using stall testing. This IFI identified a concern regarding the reliability of the values which had been derived from the stall testing. NRC inspectors noted that industry information was expected to be released that would affect the confidence in this methodology.

The licensee stated that a continued review of industry information had not revealed any information that affected Farley's confidence in the reduced-voltage outputs obtained from stall testing. The inspector was informed that licensee personnel would remain alert for such information.

To resolve the NRC concern regarding the licensee's use of reduced-voltage capabilities based on stall testing, the licensee offered that the reduced-voltage output capabilities of all but six MOV's would be assured through reduced-voltage torque limits employed in Farley's periodic verification testing. The torque limits had been determined through equations endorsed by the actuator manufacturer rather than through stall tests. From a review of test records, the inspector verified that the licensee had begun use of the reduced-voltage torque limits during the previous outage. This resolved the original concern except for the six MOV's referred to by the licensee.

The reduced-voltage torques of the six MOV's referred to in the previous paragraph could not be satisfactorily evaluated during the licensee's periodic verification testing because the licensee does not have the capability to directly measure their torques. To support the adequacy of the reduced-voltage capabilities for the six MOV's, the licensee provided data demonstrating that their calculated reduced-voltage torque capabilities exceeded the torques estimated for opening and closing torque requirements by a sufficient amount to accomodate any uncertainty in the values. For closing, the calculated reduced-voltage torque capability of each MOV was over twice the estimated maximum torque setting permitted by its actuator's limiter plate and spring pack. Diagnostic test results indicated that the reduced voltage thrust and torque requirements for opening would be less than for closing. Based on his review of the data for these MOV's, the inspector considered the original concern to be resolved. This IFI is closed.

i. (Closed) IFI 50-348, 364/94-28-11, Review of Licensee Corrective Action Criteria for Overthrust Events

This IFI identified a concern that criteria the licensee used to evaluate overthrust events had not been endorsed by the MOV actuator manufacturer, Limitorque. This criteria had been supplied by Westinghouse and the licensee stated that they were in the process of obtaining documented acceptance from Limitorque.

In the current inspection the inspector verified that the licensee had received Limitorque endorsement of the subject criteria. This was documented in correspondence from P. McQuillan of Limitorque to S. Gates of Southern Nuclear Operating Company, dated January 5, 1996. This IFI is closed.

j. (Closed) IFI 50-348, 364/94-28-12, Review of Motor Load Unit Used in Packing Adjustment

During Inspection 94-28, NRC inspectors had expressed concern that the licensee's post maintenance testing procedure permitted use of the MLU to assess packing loads. The inspectors found that the licensee did not have data which fully supported the adequacy of the MLU. The licensee stated that, coupled with engineering judgements that recognized its limitations, the MLU was a satisfactory test. This IFI was opened to verify that the MLU was used appropriately.

An inspector questioned the licensee as to their application of the MLU and was informed that its use prior to IR 94-28 had been very limited and its use was discontinued immediately following IR 94-28. The inspector noted that MOV program procedures still permitted use of the MLU. The licensee indicated that this was an oversight and would be corrected. This IFI is closed.

5.0 PLANT SUPPORT (71750, 83750, 84750 AND 92904)

5.1 Fire Protection

During normal tours, inspectors routinely examined aspects of the plant FP Program (e.g., transient fire loads, flammable materials storage, fire brigade readiness, ignition source/risk reduction efforts & FP features). In general, plant personnel and equipment conformed with the established FP Program. Several minor problems were discussed and resolved with the onsite Fire Marshall.

5.2 Security

During routine inspection activities, inspectors verified that security program plans were being properly implemented. This was evidenced by: proper display of picture badges; appropriate key carding of vital area doors (except as noted below); adequate stationing/tours of security personnel; proper searching of packages/personnel at the Primary Access Point; and adequacy of compensatory measures during disablement of vital

area barriers. Licensee activities observed during the inspection period appeared to be adequate to ensure proper plant physical protection. Guards were observed to be alert and attentive while stationed at disabled doors, and responded promptly to open door alarms. Posted positions were manned with frequent relief.

5.3 Health Physics

Inspectors routinely examined postings and surveys of radiological areas and labelling of radioactive materials in the RCA. Work activities of plant personnel in the RCA were observed to adhere to established administrative guidelines for radiation protection and ALARA work practices. Effluent and environmental radiation monitors were monitored on a routine basis for any significant changes in radiological conditions or indications of uncontrolled releases. No significant findings were identified. HP technicians maintained positive control over the RCA and provided good support of Unit 1 and 2 steady-state operations and maintenance activities. HP management continued to keep the resident staff well informed of potential radiological issues.

NRC Form 3

The inspector reviewed the licensee's radiation control program to determine whether the NRC Form 3 had been posted in accordance with the requirements of 10 CFR 19.11.

Procedure O-RCP-5, Radiation Control and Protection Procedure (Revision 40, 12/19/95) lists NRC Form 3 as one of the forms which must be posted at key locations in the plant. On January 6, 1996, the licensee inspected all 13 locations in the plant which this form is required to be posted and verified that the correct form was posted. The inspector reviewed the licensee's inspection check list and independently reviewed the NRC Form 3 which was posted at seven locations. The NRC Form 3 posted at these locations was in good condition and was the current revision. No violations or deviations were identified.

5.4 Occupational Radiation Exposure

a. Changes

Changes in the RP program, since the last inspection, were reviewed to assess their impact on the effective implementation of the RP program.

The inspection focused on changes in organization, personnel, facilities, equipment, programs, and procedures. The previous inspection in the RP area was made August 14-18, 1995. With the exception of organizational and certain personnel changes the licensee had not made any significant changes in the RP program.

By observation and discussion with cognizant supervisory and management personnel the inspector determined that the licensee had

made several organizational and personnel changes in the site's organization impacting the RP program area. The changes were to be effective on February 5, 1996.

The organization chain of command from the RPM to the Technical Manager to the AGM - Operations had not changed. However, the Technical Manager was scheduled to perform other duties in the next two years. A decision to replace the Technical Manager with an interim manager had not been determined at the time of the inspection.

The previous HP organization included a Radwaste Supervisor, HP Supervisor and Plant Health Physicist who reported to the HP Superintendent (i.e., RPM). With the new organization structure the Radwaste Supervisor position within the HP group was eliminated. However, some responsibilities such as decontamination, laundry, and waste handling were transferred out of the HP group to the Facilities group which was assuming duties within the RCA. Other duties previously performed by the Radwaste Supervisor (Transportation of Radioactive Material/Waste) were transferred to the Plant Health Physicist position. Prior to this organizational change, the Facilities Supervisor had been responsible for activities outside the RCA and had little experience in the new responsibilities. However, a core of experienced foremen were also transferred to the Facilities group. The Facilities Supervisor was to immediately begin a HP training/qualification program to improve personal knowledge in current radiation control practices related to the new position.

In addition to the organization changes several HP personnel were assigned new positions. Personnel changes included the following:

The former HP Trainer entered the Operations Training program;

The former HP Supervisor moved into the vacated HP Trainer position;

The former Radwaste Supervisor moved into the vacated HP Supervisor position; and

The Plant Health Physicist was transferred to the SAER auditing group and the RP auditor in the SAER group was transferred into the Health Physicist position.

The inspectors determined that all personnel were adequately qualified to perform newly assigned responsibilities. The inspectors did not identify any concerns with the licensee's changes in organization structure or in the new personnel assignments. It did not appear that the changes would adversely affect the licensee's programs for control of radiation exposures and radioactive materials.

b. Audits

Audits of radiation protection activities were reviewed to determine the adequacy of the licensee's identification and corrective action programs for deficiencies or weaknesses related to the control of radiation or radioactive material.

The inspectors reviewed the licensee's 1994 and 1995 audits of the RP program and refueling outage activities. The inspector determined that the licensee was adequately reviewing the RP program and tracking audit findings for correction. No concerns with the licensee's audit program, findings or corrective actions were identified.

c. External And Internal Exposure Controls

This program area was reviewed to evaluate the adequacy of licensee radiation protection controls for internal and external radiation hazards and to verify individual radiation doses did not exceed the dose limits described in Subpart C of 10 CFR Part 20.

Elements of the licensee's personnel exposure control program were reviewed to assess their adequacy and compliance with applicable licensee procedures and regulatory requirements. Based on direct observation, review of records and discussions with licensee personnel the inspectors noted the following:

Reviewed RWP's provided adequate radiation protection instructions and controls;

Administrative controls such as radiation dose extensions were reviewed and effectively utilized to maintain radiation exposures below regulatory limits;

Personnel monitoring equipment was utilized appropriately;

Health physics technicians provided adequate RP job coverage for radiation workers during observed containment entries at power;

Locked high radiation areas were properly secured; and

Process and engineering controls to limit exposures to airborne radioactivity were considered and utilized when possible.

The licensee reported the following maximum doses (Rems) for individuals in calendar year 1995 and 1996 to date:

Year	TEDE	Skin	Extremity	Lens-Eye
1995	2.254	2.254	12.925	2.254
1996	0.041	0.370	0.370	0.111
Part 20 Limits	5.000	50.000	50.000	15.000
Adm. Limits	1.000	10.000	10.000	3.000
Note: 1996 data through January 29, 1996.				

The inspectors verified that the licensee had approved dose extensions for selected individuals having radiation doses greater than the licensee's administrative limits.

No individual internal exposures were greater than 0.1 ALI and the licensee had not assigned any internal exposures for 1995 or 1996.

Through review of licensee procedures and reported dose information, the inspectors concluded the licensee was implementing adequate radiation protection controls and monitoring individual occupational radiation exposures in accordance with the requirements and that all individual doses reported were within 10 CFR Part 20 limits.

d. Control of Radioactive Materials and Contamination, Surveys and Monitoring

This area was reviewed to evaluate the licensee's control of radioactive and contaminated material.

Housekeeping and the control of radioactive material within the licensee's facilities were better than the inspector had previously observed during other inspections at the Farley site, however, a decontamination room and a U1 sample room needed additional attention to eliminate trash and clutter. No uncontrolled containers of radioactive material or contamination were identified. Based on direct observation, discussion and review of records the inspector concluded the licensee was adequately controlling contamination and radioactive material.

e. Maintaining Occupational Exposures ALARA

This program area was reviewed to determine the status and effectiveness of ALARA program initiatives in reducing collective dose for the site. Areas reviewed included site annual and outage goals and objectives, U1RF13 outage report findings and the collective dose results.

A summary of recent collective dose and goals for the site is shown below.

Collective Personnel Exposures (Person-Rem)						
Year	Annual Dose		Outage Dose			
	Actual	Goal	Outage	Actual	Goal	Days
1993	333	337	U2-RF-09	294	250	69
1994	251	337	U1-RF-12	218	240	51
1995	460	450	U1-RF-13	236	175	49
			U2-RF-10	186	198	47
1996	1	250	U2-RF-11	NA	198	45

Notes:

The 1996 dose information was measured with DADs and current through January 29, 1996.

The 1996 annual goal and U2RF11 outage goals had not been formally approved.

An outage length projection was shown for U2RF11 which is scheduled to begin in October 1996.

With the exception of the most recent U1RF13 outage, the information showed that overall the collective doses continued to decreased as the outage length decreased and the licensee was implementing more effective ALARA measures.

Licensee representatives reported vendor equipment problems and use of less experienced personnel in SG inspection and maintenance activities were the primary reason the licensee exceeded the U1-RF-13 collective dose goal of 175 person-rem by 61 person-rem. Additional attention was needed to reduce collective doses for future SG testing and maintenance activities.

Despite the problems experienced in U1RF13 outage the collective dose was still the second lowest for the unit. The lowest collective dose for a U1 refueling outage was obtained in the preceding outage U1RF12 in 1994. The U2RF10 was also the second lowest collective dose for that unit. The lowest collective dose for a U2 RF outage was obtained in U2RF01 in 1982.

The inspectors verified that the licensee had conducted a successful crud burst during reactor shutdown. The licensee utilized an effective crud burst procedure and observed decreases in radiation

levels in all three SG's. Some were significantly lower than seen in U1RF12 and a few were the lowest observed for the unit.

Based on direct observation, discussion and review of records the inspectors concluded the licensee was utilizing ALARA techniques and making progress in reducing collective doses for the staff. However, the recent failure to meet U1RF13 collective dose goal indicated additional attention to reduce collective doses during refueling outages was needed.

5.5 Radioactive Waste Treatment, And Effluent And Environmental Monitoring

a. Chemistry Organization

TS 6.2 describes the licensee's organization. Inspectors reviewed the licensee's organization, staffing levels, and lines of authority as they related to the Chemistry Department to verify that the licensee had not made organizational changes which would adversely affect the ability to control radiation exposures or radioactive material.

Due to an extended training session of the Chemistry Supervisor and other temporary staff vacancies, the licensee's functional structure of the Chemistry and Environmental Department had been somewhat modified. Basically, the department was divided into two branches, Plant Chemistry and Environmental. The Environmental Supervisor, three Chemistry foremen, the Radiochemistry foreman, and the Environmental foreman reported to the Chemistry and Environmental Superintendent, who was responsible for a staff of forty-eight. The Superintendent reported to the Technical Manager. The Superintendent's goal was to have his staff highly cross-trained and to push decision-making responsibilities to the lowest practical levels to improve the department's flexibility and ability to "work smart."

The inspectors noted that the Chemistry and Environmental Department was stable and capable of executing its duties.

b. Annual Radioactive Effluent Release Report

TS 6.9.1.8 requires the licensee to submit an Annual Radiological Effluent Release Report within the specified time periods covering the operation of the facility during the previous year of operation. TS 6.9.1.9 identifies the requirements for the content and format of the report. The inspectors reviewed the report for the calendar year of 1994 to verify TS compliance. This data is summarized below and compared to those of previous years to determine potential negative plant performance trends.

FNP Radioactive Effluent Release Summary				
Abnormal Releases	1991	1992	1993	1994
Gaseous	2	1	0	0
Liquid	0	2	2	0
Total Activity Released				
Liquid Releases	Activity (Curies)			
	1991	1992	1993	1994
Fission and Activation Gases	4.05E-1	1.77E-1	1.87E-1	2.13E-1
Tritium	8.24E+2	8.18E+2	1.82E+3	1.35E+3
Gaseous Releases				
Fission and Activation Gases	4.64E+2	2.67E+1	2.20E+2	2.10E+2
Particulates	< LLD	2.31E-4	3.06E-5	1.36E-2
Iodines	1.62E-3	1.96E-4	< LLD	4.27E-3
Tritium	1.39E+2	3.51E+1	7.23E+1	1.07E+2

The inspectors noted that the 1994 reported values for gaseous particulates and gaseous iodines were substantially greater than those of previous years. Discussions with the cognizant licensee representative about these values determined that, in the case of the particulates, the licensee had converted to a new computer system in 1994, which did not differentiate between natural and man-made radioisotopes in effluent releases; and, in the case of iodines, the licensee had created a "mini crud burst" during the Unit 1 outage when a chemical degassing procedure was used on the pressurizer. The pressurizer was opened to the containment atmosphere as hydrogen peroxide was added and the iodine came out of solution and into the containment atmosphere. The released iodine was detected by the radiation monitors of the stack.

There were no changes to the REMP (as a result of the Land Use Census), the PCP, or the Radwaste Treatment Systems during 1994.

A revision to the ODCM was made to replace a milk sampling location which was no longer available.

No reportable instrumentation inoperability events occurred during this reporting period.

The inspectors reviewed the yearly dose estimates to a member of the public from radioactive materials in gaseous and liquid effluents released during 1994 and compared them to those reported for 1991, 1992, and 1993. The following table summarizes that data.

FNP Annual Cumulative Estimated Doses from Effluents					
Dose Pathway	1991	1992	1993	1994	Limit
Airborne					
Gamma Air Dose (mrad)	3.57E-2	2.71E-2	1.75E-2	1.94E-2	10
Beta Air Dose (mrad)	3.75E-2	3.29E-2	1.17E-2	1.62E-2	20
Max Organ Dose (Thyroid) (mrem)	5.92E-1	8.44E-2	1.25E-2	9.25E-2	15
Liquid					
Total Body Dose (mrem)	7.32E-2	4.86E-2	7.48E-2	2.76E-2	3
Max Organ Dose (mrem)	2.37E-1[1]	3.57E-1[1]	4.11E-1[1]	3.28E-1[2]	10
Notes: [1]GI-LLI [2]Lung					

The release of radioactive material to the environment from Farley for the years reviewed was a small fraction of the 10 CFR 20, Appendix B and 10 CFR 50, Appendix I limits. As can be seen from the data presented above, the annual dose contributions to the maximum-exposed individual from the radionuclides in liquid and gaseous effluent released to unrestricted areas were all less than four per cent of the specified limits. These results were attributed to good fuel integrity and effective treatment of radioactive material prior to release.

The following table summarizes solid radwaste shipments for the previous four years. These shipments typically include spent resins, filter sludge, dry compressible waste, and contaminated equipment.

Farley Solid Radwaste Shipments				
	1991	1992	1993	1994
Number of Shipments	78	108	64	61
Number of Irradiated Fuel Shipments	0	0	0	0
Volume (cubic meters)	150.0	239.1	66.7	50.6
Activity (curies)	1036.6	2149.1	505.6	500.5

For solid radwaste, the volume was generally declining year to year.

Based on the data, the inspectors concluded that the licensee's radwaste systems were effectively utilized and operated within their design criteria to make effluent releases that were ALARA and that the Annual Radioactive Effluent Release Report satisfied the requirements of the TS.

c. Plant Water Chemistry

Both units were operating at 100 percent power at the beginning of the current inspection. However, power was reduced to 15% in Unit 2 while the licensee performed eddy current testing on the condenser in search of a small leak which allowed a sodium intrusion. (The unit had recovered to about 40% power by the completion of the inspection.) Unit 1 was in its fourteenth fuel cycle while Unit 2 was in its eleventh fuel cycle. The last Unit 1 refueling outage was completed in the autumn of 1995, while the last Unit 2 refueling outage was completed in the spring of 1995. The inspector reviewed the plant chemistry controls and operational controls affecting plant water chemistry during 1995.

1) Primary Water Chemistry

The inspector reviewed the plant chemistry controls and operational controls affecting primary plant water chemistry since the last inspection in this area. TS 3.4.8 specifies that the concentrations of DO, chloride, and fluoride in the RCS be maintained below 0.10 ppm, 0.15 ppm, and 0.15 ppm, respectively. TS 3.4.9 specifies that the specific activity of the primary coolant be limited to less than or equal to 0.5 μCi/g DEI whenever the reactor is critical or the average temperature is greater than 500°F.

Pursuant to these requirements, the inspector reviewed daily tabular and graphical summaries for both units which correlated reactor power output to chloride, fluoride, and DO concentrations, and specific activity of the reactor coolant. For both Units 1 and 2, the arbitrarily-chosen period of December 1, 1995 through January 31, 1996 was reviewed and the parameters were determined to have been maintained well below TS limits. Typical values for DO, chloride, and fluoride were less than five ppb, less than twenty ppb, and seven ppb, respectively, for Unit 1 and less than five ppb, less than twenty ppb, and less than five ppb, respectively, for Unit 2. Typical DEI values at steady-state conditions were 2.8E-3 μCi/g for Unit 1 and 2.1E-4 μCi/g for Unit 2. Neither unit had shown any evidence of leaking fuel.

The inspectors concluded that the Primary Water Chemistry was maintained well within the TS requirements.

Early Boration

The licensee had used early boration (acid-reducing chemistry) combined with hydrogen peroxide injection (acid-oxidizing chemistry) during shutdown and cooldown of the last three refueling outages of each unit, per the proposed guidelines of the EPRI Shutdown Chemistry Committee and recommendations by the licensee's NSSS supplier, to reduce the source term.

The inspectors reviewed reports/evaluations of the last early boration results for each unit. For Unit 1, the process solubilized 930 curies of Co-58 and 2151 grams of nickel (which can be activated during power operation to produce Co-58). These materials were removed via the CVCS demineralizers. Likewise, for Unit 2, the process solubilized 2186 curies of Co-58 and 3027 grams of nickel. The SG channel head dose rates decreased for each of the three SG's of each unit during their respective outages, indicating successful early boration results.

Based on the results of these reports, the inspectors concluded that the licensee was proactive in trying to reduce dose rates by removing significant quantities of activity via its early boration/hydrogen peroxide shutdown program.

Zinc Addition and Monitoring System Status

Use of the ZAMS as a pilot program on Unit 2 was suspended after the fuel cycle 10 when a dark layer of corrosion products was observed deposited on the fuel cladding and excessive clad oxide growth was measured. The licensee became concerned that zinc injection was the cause and it would adversely affect the heat transfer capabilities of the cladding or lead to premature cladding failure. SNC and the vendor (for both ZAMS and the fuel) initiated a comprehensive research project to determine the cause

of the corrosion products and clad oxide growth, and its effects on the cladding and heat transfer characteristics.

Subsequent clad thickness measurements of Unit 1 fuel following fuel cycle 13 discovered similar problems with unexpected oxide growth. Suggesting that zinc may not be the cause since Unit 1 had not used zinc injection. During U1RF13, the licensee proceeded with its original plans to install a ZAMS on Unit 1. The system incorporated features of the Unit 2 prototype as well as modifications based on operating experiences.

Research results and analysis by the fuel vendor have indicated that the corrosion model used by the vendor for predicting clad oxidation was not accurate and nonconservative. An updated model was sent to NRR for review and approval. A final report on the Unit 2 fuel-related problems is expected during the spring of 1996. Based on this report and other evaluations, the licensee will consider resuming zinc injection for mitigating PWSCC in Alloy 600 materials and its ability to reduce radiation fields by limiting corrosion product transport via the primary coolant.

The inspectors concluded that ZAMS was reducing dose rates by removing significant quantities of cobalt activity from the RCS while simultaneously attempting to control the initiation and progression of PWSCC in Unit 2.

2) Secondary Water Chemistry

TS 6.8.3.c requires the licensee to maintain a Secondary Water Chemistry Program to inhibit SG tube degradation.

General Program and Results

The inspectors discussed the licensee's Secondary Water Chemistry Program with cognizant licensee personnel. The licensee currently used a regimen of ETA, at a concentration of 1 ppm (for both units); hydrazine, at a concentration of 110 to 120 ppb (for both units); and boric acid, at a concentration of 5 to 10 ppm (for both units). For crevice control, the licensee was also using molar ratio control, maintaining the ratio of Na/Cl (as measured in the SG blowdown) in the range of 0.12 to 0.50.

The inspectors also discussed the licensee's efforts in sludge removal from the SG's. The licensee had done sludge lancing but had not done any form of chemical cleaning (nor was any planned). Results of the licensee's sludge removal over the life of the units are summarized below.

Farley Sludge Removal History			
Unit 1			
Fuel Cycle No.	SG 1A (lbs.)	SG 1B (lbs.)	SG 1C (lbs.)
1	266	611	643
2	297	1391	1359
3	Not done during this outage.		
4	834	875	1577
5	1329	1018	1097
6	1163	1006	932
7	1111	854	683
8	976	1008	778
9	472	516	482
10	294	303	248
11	263	267	255
12	193	204	181
13	174	148	188
Unit 2			
Fuel Cycle No.	SG 2A (lbs.)	SG 2B (lbs.)	SG 2C (lbs.)
1	266	213	321
2	269	485	405
3	496	418	542
4	382	391	471
5	1172	976	1093
6	496	603	719
7	329	404	251
8	258	296	226
9	363	225	222
10	117	62	97

The inspectors noted that the levels of sludge removed per SG continued a generally declining trend but that the rate of decline had slowed during the last several refueling outages.

The inspectors discussed tube plugging of the SG's with cognizant licensee personnel. Total tubes plugged to date in the Unit 1 SG's include 272, 165, and 257 in SG "A," SG "B," and SG "C," respectively. For Unit 2, 314, 199, and 198 total tubes had been plugged to date in SG "A," SG "B," and SG "C," respectively. The worst-plugged SG of Unit 1 (SG "A") had 8.10% of its tubes plugged, while the worst-plugged SG of Unit 2 (SG "A") had 9.39% of its tubes plugged.

Unit 2 Sodium Intrusion

In late April 1995, after the startup of Unit 2 from its last refueling outage (U2RF10), sodium concentrations were observed to be much higher (up to 70 ppb) than expected, as measured in the SG blowdown. Over the next several weeks, as plant power was increased, the sodium concentration would also increase before easing back to reduced, but higher than normal levels. An extensive effort was made by the licensee to identify the sodium source. Minor condenser tube leaks were found and plugged but the problem remained. The licensee eventually deduced the sodium source was located between the inlet to the low-pressure turbine and the #4 Heater Shell-Side Drain. A task force was assembled to identify every chemical product and process which could have been utilized in that part of the system during the refueling outage. The results of the task force study are expected soon. After extensive flushing and as the fuel cycle went on, the sodium intrusion was reduced to a manageable level, although still markedly higher than Unit 1.

Also, for the last several months, condenser in-leakage has shown sodium concentrations in the range of 0.5 to 0.9 ppb, while concentrations in the SG blowdown were approximately twice their normal value (0.30 ppb versus 0.15 ppb), from another unknown source. Approximately every three months the licensee has conducted a sodium flush, which required the plant to operate at 15% power to optimize the flush. The licensee conducted a flush during the week of the inspection and did eddy current testing of the "A" waterbox of the "A" condenser in an effort to find the leaking tube. None were found but four tubes were plugged due to external "dings" as a precaution, not due to through-wall leaks. The licensee would consider eddy current testing of condenser tubes in other waterboxes during future flushes.

Based on this review, the inspectors concluded that the licensee had taken appropriate steps to preserve/protect its SG's through its Secondary Water Chemistry Program.

Based on these observations, the inspectors concluded that the licensee had maintained an effective over-all chemistry program to not only inhibit degradation due to corrosion/erosion of components of both the primary and secondary systems, but to reduce potential dose to its personnel.

d. Radiological Environmental Monitoring Program

TS 6.8.3.f requires the licensee to provide a program to monitor the radiation and radionuclides in the environs of the plant.

The Farley Nuclear Plant Environmental Monitoring Program is designed to detect the effects, if any, of plant operation on environmental radiation levels by monitoring airborne, waterborne, ingestion, and direct radiation pathways in the area surrounding the plant site. Indicator sampling stations are located where detection of the radiological effects of the plant's operation would be most likely, where the samples collected should provide a significant indication of potential dose to man, and where an adequate comparison of predicted radiological levels might be made with measured levels. Control stations are located where radiological levels are not expected to be significantly influenced by plant operation, i.e., at background locations. An environmental impact assessment of plant operation is made from the radiological readings of the sampling stations.

1) Annual Radiological Environmental Operating Report

TSs 6.9.1.6 delineated the requirements for submitting, the submittal dates, and the content of the Annual Radiological Environmental Operating Report. The report was required to be submitted prior to May 1 of each year and to provide an assessment of the observed impact on the environment resulting from plant operations during the previous calendar year.

The inspectors reviewed the licensee's 1994 Annual Radiological Environmental Operating Report and discussed its content with the licensee. The report was submitted in compliance with TS 6.9.1.6 on April 20, 1995, and included the following: a description of the program, a summary and discussion of the results for each exposure pathway, analysis of trends and comparisons with previous years and preoperational studies, and an assessment of the impact on the environment resulting from plant operations. The report also included the results of the Land Use Census. (There were no changes to the environmental monitoring network during 1994 due to those results.) The following observations for the various exposure pathways were produced by the licensee's evaluation of the 1994 environmental monitoring program data, and documented in the report, or were noted by the inspector during the review of the report.

- Airborne - Air samples were analyzed for radioiodine and airborne particulates (gross beta) as part of the REMP during 1994. All charcoal cartridge samples showed radioiodine activities of less than the nominal MDC of 0.025 pCi/m^3, i.e., no radioiodine was detected in any of the samples. Analysis of particulate filters determined the mean beta activities from all of the indicator locations to be 0.019 pCi/m^3, the same as of the control locations and therefore not considered to be the result of plant operations. Except for naturally-occurring Be-7, no other radionuclides were detected in any 1994 airborne particulate samples.

- External Radiation - The mean external gamma doses measured in 1994 were slightly greater than those of the pre-operational period, but less than those of 1993. The highest mean annual dose (87.5 mrem) at a single location was measured at station RI-0401, located on the plant perimeter 0.8 miles east of the plant. It was noted that the mean (58 mrem) of the indicator locations was only slightly higher than that of the control locations (50 mrem).

- Milk - A total of twenty-six milk samples were collected from the control dairy. There were no indicator samples collected in 1994. The 1994 results were consistent with those of previous years. Only naturally-occurring K-40 was detected in the milk samples, at a mean of 1350 pCi/l.

- Vegetation - The 1994 analysis results were below pre-operational levels and consistent with the downward trends of recent years. Mean values of naturally-occurring Be-7 and K-40 at the indicator locations were 1032 pCi/kg and 4077 pCi/kg, respectively.

- Soil - The insitu soil analysis was discontinued in 1994 because there is no requirement that it be performed.

- Surface Water - No tritium activity was detected in any of the samples. (The MDC for tritium was 271.5 pCi/l).

- Ground Water - No radionuclide activity was detected in ground water samples collected during 1994.

- River Sediment - Activity from Cs-137 and various naturally-occurring isotopes was measured in control and indicator samples. For Cs-137, its mean activity was determined to be 29 pCi/kg at the indicator locations versus 11 pCi/kg at the control locations and represented an almost 70% reduction from the reported value of the previous year.

- Game Fish - Only Cs-137 activity (at a mean of 19 pCi/kg wet) and naturally-occurring K-40 (at a mean of 2930 pCi/kg wet) was detected in the indicator game fish samples taken. The detected activity was below pre-operational levels and consistent with levels of previous years.

- Bottom-Feeding Fish - Only Cs-137 activity (at a mean of 15.9 pCi/kg wet) and naturally-occurring K-40 (at a mean of 2730 pCi/kg wet) were detected in samples of bottom-feeding fish. The detected activity was below pre-operational levels and consistent with levels of previous years.

The report's summary section indicated that the contribution to the environmental radioactivity resulting from plant operations was minimal and it had no significant radiological impact and yielded virtually no dose to members of the general public. The inspector determined that the Report was in compliance with the TS.

2) Observation of Sample Collection

The inspector accompanied a technician on his normal weekly rounds to collect samples to observe collection technique and to check the physical condition and operability of the sampling stations. Air samples were taken at four stations, including: 0215, 0703, 0718, and 1605. In addition, TLD's were observed at each of the stations. The air sampling stations were located in areas generally free of tall weeds/vegetation which might interfere with obtaining representative samples. The inspector noted that all of the air sampling units were within calibration and were well-maintained. The inspector noted that the TLD's were properly located and that there was no evidence of vandalism. Two water samples were also collected, one at the control station at Andrews Locks upstream of the site and one at the indicator station at a wood processing plant downstream of the site. The inspector noted that both of the water sampling units were within calibration and were well-maintained. The inspector noted a deficiency tag on the water sampling unit at Andrews Locks dealing with sample volume collected. (The volume satisfied the minimum requirements but the technician collecting the sample felt that there was insufficient margin for error and, therefore, requested a greater sample volume to be collected.) The inspector noted that it was not necessary for the technician to review the procedures (FNP-0-STP-791.0, Rev. 12, "Air Particulates and Iodine Sampling" and FNP-0-STP-791.0, Rev. 10, "River Water Samples") because he was so familiar with the station locations and media to be collected at each. The inspector also noted that the licensee used a quick disconnect assembly containing the charcoal canister and particulate filter, which allowed easy retrieval of the samples and installation of the new assembly, even in adverse weather conditions.

The inspectors concluded that the technician was knowledgeable, well-trained, conducted his activities in a competent manner and that the sampling stations were well-maintained.

Based on the above review, the inspectors concluded that the licensee had a good program in place to detect the effects of radiological effluents, direct radiation, etc. due to plant operations and that those operations had caused minimum impact to the environment and virtually no dose to the general public. The licensee had complied with the sampling, analytical, and reporting program requirements and its radiological environmental monitoring program had been effectively implemented.

e. Control Room Emergency Ventilation System

Per 10 CFR 50, Appendix A, GDC 19, licensees shall assure that adequate radiation protection be provided to permit access to and occupancy of the control room under accident conditions and for the duration of the accident. Specifically, operability of the CREVS ensures that 1) the ambient air temperature does not exceed the allowable temperature for continuous duty rating for the equipment and instrumentation cooled by this system and 2) the control room remains habitable for operations personnel during and following all credible accident conditions such that the radiation exposure to personnel occupying the control room is limited to 5 rem or less whole body, or its equivalent.

TS 3.7.7 defines operability requirements for the control room emergency air cleanup systems, while TS 4.7.7 prescribes the surveillance requirements.

The inspectors reviewed the P&IDs (D-175012, Rev. 27, and D-205012, Rev. 25) which showed the general layout of the components of the Control Room Air Conditioning System for Unit 1 and Unit 2, respectively. The inspectors walked down the system, from the air intake to the MCR, to air exhaust, noting the major components, such as isolation dampers, filter banks, fans, radiation detectors, etc. All components were well-maintained, with no sign of physical degradation. The inspectors reviewed the System Description, as described in Section 9.4.1 of the FSAR, and discussed system operation under both normal and emergency conditions with cognizant licensee personnel.

The inspectors reviewed summaries of TS-required surveillances conducted in the last several years for the HEPA filters, carbon adsorber banks, positive pressure in the MCR, and heater energy dissipation. The most recent surveillances of the HEPA filters and charcoal adsorber banks had been conducted on June 22, 1995 on both trains. The work was done by a contractor using FNP-0-STP-123.0, Rev. 8, "Control Room Emergency Ventilation Performance Test," issued December 3, 1991. The documentation included a NIST traceable Certificate of Calibration for the freon monitor (used to determine

the upstream to downstream sampling ratio), as well as a Certificate of Calibration and Testing for the air velocity meter used. The most recent surveillances of the MCR positive pressure differential were done in April 1995 for both trains using FNP-0-STP-26.2, Rev. 10, "Control Room Pressurization Operability Test. The most recent surveillances of the MCR HVAC heaters were done in April 1995 for both trains using FNP-0-STP-916.0, Rev. 3, "Control Room Ventilation System Heater Test. The inspectors determined that TS compliance had been met and the respective acceptance criteria satisfied.

Based on the scope of this review, the inspectors concluded that the system was adequate for its intended function and that it was being maintained in compliance with applicable TS.

5.6 Plant Support Followup

a. (Closed) VIO 348, 364/95-05-02, Failure to Establish and Maintain Fire Watches With Portions of the Facility Fire Protection System Disabled.

The licensee responded to this violation by letter dated May 2, 1995. The inspector reviewed FNPIR Nos. 1-94-262 and 1-95-052 which described the events and the corrective actions implemented to avoid further violations. FNP-1/2-STP-914, Auxiliary Building Battery Charger Load Test (Revision 3) were reviewed and the inspector verified that these procedures had been revised to require notification of the SS when a battery charger is returned to service and the isolated fire zone has been untagged, unisolated and returned to service. FNP-0-FSP-56, High Pressure CO_2 Systems (Revision 1) was reviewed and the inspector noticed that this procedure had been revised to require both the main and reserve solenoid valves to be reconnected following completion of testing. Also, a separate signoff had been provided for each valve. FNP-0-SOP-0.4, Fire Protection Program Administration Procedure (Revision 29) was reviewed and the inspector noticed that this procedure had been revised to provide guidance on the effect of pipe openings through fire barriers and to provide the associated fire watch requirements.

Based on discussions with site fire protection and Operations personnel, and review of the above FNPIR's and procedures, the inspector found that the licensee had completed the corrective actions to avoid further violations. This VIO is closed.

b. (Closed) VIO 364/95-08-04, Loss of Personnel and Material Control in the Unit 2 Spent Fuel Pool Controlled Refueling Area Boundary.

The licensee responded to this violation by letter dated May 31, 1995. The inspector reviewed FNPIR 2-95-105 which provided a description of the event and the corrective actions implemented to avoid further violations. FNP-0-ACP-7.0, Foreign Material Control in Fuel Handing Areas and Spent Fuel Pool Material Storage (Revision 3)

was reviewed and the inspector noted that the procedure had been revised to include provisions for the assessment of the work scope by the responsible work group and the requirement to establish a CRAB access control point monitor when deemed necessary. Based on review of the licensee's incident report and the revisions to this procedure and discussions with Operations and Radiation Protection personnel, the inspector concluded that the licensee had completed the corrective actions to avoid further violations. This VIO is closed.

c. (Closed) VIO 364/95-13-01, Missed Technical Specification - Dose Equivalent Iodine; LER 364/95-006, Missed Technical Specification Surveillance Requirement 4.4.9.

The licensee responded to the violation by letter dated September 11, 1995. An inspector reviewed FNPIR 2-95-156 which provided a description of the event and the corrective action implemented to avoid further violations. FNP-1/2-UOP 2.1, Shutdown of Unit from Minimum Load to Hot Standby (Unit 1 Revision 27 and Unit 2 Revision 17), UOP-3.1, Power Operations (Unit 1 Revision 39 and Unit 2 Revision 29) and AOP-17, Rapid Load Reductions (Unit 1 Revision 5 and Unit 2 Revision 6) were reviewed. The inspector noted that these procedures had been revised to require Operations to notify Chemistry of any significant power changes and for the Chemistry group to perform STP-746, DEI-131 Determination of the Reactor Coolant System, following significant power changes. The inspector also reviewed FNP-1/2-CCP-203, Chemistry and Environmental Group Considerations During Operational Transients (Revision 0), which were issued on December 20, 1995, to provide references to procedures and guidance during operational transients, unusual or unexpected events, TS contingencies and planned operational changes.

Based on review of the licensee's incident report, procedure revisions, issuance of the new guidance procedure, and on discussions with Operations and Chemistry personnel, the inspector concluded that the licensee has completed the corrective actions to avoid further violations. The corrective actions implemented for the LER were essentially the same as for the violation. Therefore, both of these items are closed.

6.0 Review Of FSAR Commitments

A recent discovery of a licensee operating its facility in a manner contrary to the FSAR description highlighted the need for a special focused review that compares plant practices, procedures, and/or parameters to the FSAR descriptions.

While performing the inspections discussed in this report, the inspectors reviewed the applicable portions of the FSAR that related to the areas inspected. The inspectors verified that the FSAR wording was consistent with the observed practices, procedures, and/or parameters.

7.0 EXIT INTERVIEW

On January 12, 1995, a preliminary exit meeting was held at SNC corporate offices in Birmingham, Alabama. The scope and results of the GL 89-10 open item followup inspection were summarized with those persons indicated in section 1.0. Details of this inspection are described in Section 4.2.

On February 9, 1996, the SRI conducted a final exit meeting with licensee management (see section 1.0) to present a summary of inspection scope and findings. During this meeting the inspectors summarized the scope and findings of the inspection as detailed in this report. SNC management at FNP acknowledged these findings and identified the ZAMS process as developmental/proprietary. This process was not discussed in detail in this report. The licensee did not express any dissenting comments. The status of all open items discussed in this report are as follows:

TYPE	ITEM NUMBER	STATUS	DESCRIPTION AND REFERENCE
IFI	50-348, 364/94-21-02	Closed	GE HEA Lockout Relay Failure (Section 3.18.b)
IFI	50-348, 364/94-28-01	Open	Evaluation of Settings for Copes-Vulcan MOV's 8811A/B and 8812A/B Using the EPRI PPP Model (Section 4.3.a)
IFI	50-348, 364/94-28-02	Open	Evaluation of Settings for Westinghouse Unit 2 MOV 8811A Using the EPRI PPP Model (Section 4.3.a)
IFI	50-348, 364/94-28-03	Open	Evaluation of Settings for Pratt Butterfly MOV's Using the EPRI PPP Model (Section 4.3.a)
IFI	50-348, 364/94-28-04	Closed	Resetting the Torque Switches of 30 MOV's to Higher Values (Section 4.3.b)
IFI	50-348, 364/94-28-05	Closed	Updating Setpoint Documents (Section 4.3.c)
IFI	50-348, 364/94-28-06	Closed	Replacement of Reduced-Voltage Outputs Provided by Westinghouse (Section 4.3.d)
IFI	50-348, 364/94-28-07	Closed	Updating of Reduced-Voltage Thrusts in Design Documents (Section 4.3.e)
IFI	50-348, 364/94-28-08	Closed	Periodic Verification of MOV Capabilities (Section 4.3.f)

IFI	50-348, 364/94-28-09	Closed	Periodic Verification of Capabilities of 1500# 10 and 14 Inch Copes-Vulcan Gate Valves (Section 4.3.g)
IFI	50-348, 364/94-28-10	Closed	Applicability of Industry Information to MOV Reduced-Voltage Output Determined by Farley Test (Section 4.3.h)
IFI	50-348, 364/94-28-11	Closed	Review of Licensee Corrective Action Criteria for Overthrust Events (Section 4.3.i)
IFI	50-348, 364/94-28-12	Closed	Review of MLU Use in Packing Adjustment (Section 4.3.j)
IFI	50-348, 364/95-03-01	Closed	SWS Room Temperature Control (Section 3.18.c)
VIO	50-348, 364/95-05-02	Closed	Failure to Establish and Maintain Fire Watches With Portions of the Facility Fire Protection System Disabled (Section 5.6.a)
VIO	50-364/95-08-04	Closed	Loss of Personnel and Material Control in the Unit 2 Spent Fuel Pool Controlled Refueling Area Boundary (Section 5.6.b)
VIO	50-364/95-13-01	Closed	Missed TS Surveillance - Dose Equivalent Iodine (Section 5.6.c)
URI	50-348, 364/95-14-01	Closed	High Containment Air Temperature (Section 2.12.b)
VIO	50-348/95-16-01	Closed	Improperly Installed Scaffolds Over Safety-Related Equipment (Section 2.12.a)
LER	50-364/95-006	Closed	Missed Technical Specification Surveillance Requirement 4.4.9. (Section 5.6.c)
LER	50-348/95-007	Closed	Control Room Pressurization Unit Moisture Controller (Section 3.18.a)
VIO	50-348, 364/95-18-01	Closed	Inoperable Control Room Pressurization Unit Humidistats, was closed (Section 3.18.a)

URI	50-364/95-20-04	Closed	Mode Change With Inoperable Source Range Detector (NI-32) (Section 2.12.c)
NCV	50-364/95-21-01	Closed	Inadequate Control Of TS Requirements For The Specified Asterisk Condition (Section 2.9)
VIO	50-348, 364/95-21-02	Open	Excessive Maintenance Overtime During Refueling Outages (Section 3.17)

8.0 ACRONYMS AND ABBREVIATIONS

AC - Alternating Current
ACP - Administrative Control Procedure
AFW - Auxiliary Feedwater
AGM - Assistant General Manager
ALARA - As Low As Reasonably Achievable
ALI - Annual Limit on Intake
AOP - Abnormal Operating Procedure
AP - Administrative Procedure
CCB - Configuration Control Board
CCP - Chemical Control Procedure
CCW - Component Cooling Water
CFR - Code of Federal Regulations
Ci - curie
CO_2 - Carbon Dioxide
CRAB - Control Refueling Area Boundary
CRDM - Control Rod Drive Mechanism
CREVS - Control Room Emergency Ventilation System
CVCS - Chemical and Volume Control System
DAD - Digital Alarming Dosimeter
DC - Direct Current
DCN - Design Change Notice
DCR - Design Change Request
DEI - Dose Equivalent Iodine
DO - Dissolved Oxygen
EDG - Emergency Diesel Generator
EHC - Electrohydraulic Control
elev. - Elevation
EM - Electrical Maintenance [Department]
EMP - Electrical Maintenance Procedure
EPRI - Electric Power Research Institute
EPB - Emergency Power Board
ES - Engineering Support [Department]
ETA - Ethanolamine
F - Fahrenheit
FEMA - Federal Emergency Management Agency
FNP - Farley Nuclear Plant
FNPIR - Farley Nuclear Plant Incident Report

FP - Fire Protection
FSAR - Final Safety Analysis Report
FSP - Fire Protection Surveillance Procedure
g - gram
GDC - General Design Criteria
GI - Gastrointestinal
GL - Generic Letter
GMP - General Maintenance Procedure
HEPA - High Efficiency Particulate Air1
HP - Health Physics
HX - Heat Exchanger
HVAC - Heating, Ventilation, and Air Conditioning
I&C - Instrumentation and Control [Department]
IAW - In Accordance With
IFI - Inspector Followup Item
IMP - Instrument Maintenance Procedure
INPO - Institute of Nuclear Power Operations
IR - Inspection Report
IST - Inservice Test
kg - kilogram
l - liter
lb - pound
LCO - Limiting Condition for Operation
LER - Licensee Event Report
LLD - Lower Limit of Detection
LLI - Lower Large Intestine
LP - Low Pressure (steam)
μCi - micro-Curie (1.0E-6 Ci)
m - meter
MCB - Main Control Board
MCR - Main Control Room
MDAFW - Motor-driven Auxiliary Feedwater
MDC - Minimum Detectable Concentration
MG - Motor-Generator
MLU - Motor Load Unit
MM - Mechanical Maintenance
MOV - Motor-Operated Valve
mrad - milli-Rad
mrem - milli-rem
MTG - Main Turbine Generator
NCV - Noncited Violation
NI - Nuclear Instrumentation
NIS - Nuclear Instrumentation System
NIST - National Institute of Standards and Technology
No. - Number
NRC - U.S. Nuclear Regulatory Commission
NRR - Nuclear Reactor Regulation [U.S. NRC]
NSSS - Nuclear Steam Supply System
ODCM - Off-site Dose Calculation Manual
P&ID - Piping and Instrumentation Diagram
PAHA - Post-accident Hydrogen Analyzer
pCi - pico-Curie (1.0E-12 Ci)

PC - Printed Circuit [Card]
PCP - Process Control Program
PM - Preventive Maintenance
PMD - Plant Modification and Design [Department]
POD - Plan of the Day
ppb - parts per billion
ppm - parts per million
PPP - Performance Prediction Program
PPR - Piping Penetration Room
PR - Power Range
PRF - Penetration Room Filtration
PWSCC - Primary Water System Stress Corrosion Cracking
RCA - Radiological Control Area
RCP - Radiological Control Procedure
RCS - Reactor Coolant System
REA - Request For Engineering Assistance
REMP - Radiological Environmental Monitoring Program
RG - Regulatory Guide
RHR - Residual Heat Removal
RMWST - Reactor Makeup Water Storage Tank
RP - Radiation Protection
RPM - Radiation Protection Manager
RO - Reactor Operator
RWP - Radiation Work Permit
SAER - Safety Audit and Engineering Review
SFO - Shift Foreman - Operating
SFP - Spent Fuel Pool
SG - Steam Generator
SGBD - Steam Generator Blowdown
SI - Safety Injection
SGFP - Steam Generator Feed Pump
SNC - Southern Nuclear Operating Company
SO - System Operator
SOP - Standard Operating Procedure
SS - Shift Supervisor
SSPS - Solid State Protection System
STP - Surveillance Test Procedure
SWS - Service Water System
SWIS - Service Water Intake Structure
TDAFW - Turbine-driven Auxiliary Feedwater
TE - Temperature Element
TEDE - Total Effective Dose Equivalent
TLD - Thermoluminescent Dosimeter
TM - Technical Manual
TO - Tag Order
TS - Technical Specifications
U1RF12 - Unit 2 Twelfth Refueling Outage
U1RF13 - Unit 2 Thirteenth Refueling Outage
U1RF14 - Unit 2 Fourteenth Refueling Outage
U2RF10 - Unit 2 Tenth Refueling Outage
U2RF11 - Unit 2 Elventh Refueling Outage
URI - Unresolved Item

UOP - Unit Operating Procedure
VIO - Notice of Violation
WO - Work Order
ZAMS - Zinc Addition and Monitoring System