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

Report Nos.: 50-348/92-20 and 50-364/92-20

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 1 and 2

Inspection Conducted: June 29 - July 24, 1992

Inspectors: [signature] for 8/7/92
M. J.Morgan, Acting Sr. Resident Inspector Date Signed

Accompanying Personnel: James J. Raleigh

Approved by: [signature] 8/7/92
Floyd S. Cantrell, Chief Date Signed
Project Section 1B
Division of Reactor Projects

SUMMARY

Scope:

This routine, resident inspection involved on-site inspection in the areas of operations, maintenance activities, surveillance testing, fire protection, electrical distribution, event follow-up, licensee self-assessment capability and actions on previous inspection findings. Deep backshift inspections were conducted July 21, July 22 and July 23, 1992.

Results:

On July 1, the EOF and TSC Emergency Notification network (ENN) stations were returned to service after testing; however, the licensee had not been aware that any part of the ENN was out of service, a backup system had not been established as required by procedures. A violation was cited, paragraph 8. On July 4, Steam Generator Feedwater Pump (SGFP) "2A" tripped on low oil pump pressure, paragraph 3.b. On July 8, maintenance personnel swapped pump field leads, paragraph 4.b. On July 9, Southern Nuclear Company contracted steam generators for both units. Estimate for the first unit is 2005. On July 15, a site fire main pipe ruptured. From July 22-24, emergency loading sequencer surveillances were performed to determine operability, paragraph

5. In a recent unit outage, the containment sump was opened by health physics personnel without a clearance being released

and a red "Hold" tag was not properly removed. A non-cited violation was issued, paragraph 3.c.

Except as noted, no other deviations/violations were identified. Results of this inspection indicate that actions by management, operations, maintenance and other site personnel were adequate.

REPORT DETAILS

1. Persons Contacted

   Licensee Employees

   W. Bayne, Supervisor, Safety Audit and Engineering Review
   R. Coleman, Plant Modification Manager
   L. Enfinger, Manager, Administration
   *S. Freeman, Sr. Engineer Safety Audit and Engineering Review
   *S. Fulmer, Superintendent, Operations Support
   R. Hill, General Manager - Farley Nuclear Plant
   *M. Mitchell, Superintendent, Health Physics and Radwaste
   C. Nesbitt, Operations Manager
   *J. Osterholtz, Technical Manager
   *L. Stinson, Assistant General Manager - Plant Operations
   J. Thomas, Maintenance Manager
   *L. Williams, Training Manager
   B. Yance, Manager, Systems Performance

   Other licensee employees contacted included, technicians, operations personnel, security, maintenance, I&C and office personnel.

   *Attended exit interview

   During the week of June 29 - July 2, McGuire Resident Inspector, T. Cooper, assisted the site resident inspectors.

   During the week of July 13 - 17, Calvert Cliffs Resident Inspector, C. Lyon, assisted the site resident inspectors.

   During the week of July 20 - 24, Catawba Senior Resident Inspector, W. Orders, assisted the site resident inspectors.

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

2. Plant Status

   a. Unit 1 Status

      Unit 1 operated at approximately 100 percent power for most of the reporting period.

   b. Unit 2 Status

      Unit 2 operated at approximately 100 percent power for most of the reporting period. However, on July 5, reactor power was reduced to approximately 70 percent power to investigate problems discovered with the "2A" SGFP main oil pumps (MOPs). The unit was returned to 100 percent power operation on July 10.

c. Other NRC/Licensee Meetings and Inspections

During the week of July 6, a Region II Electrical Distribution System Functional Inspection (EDSFI) was performed. An team exit meeting was conducted on July 10. (Inspection Report 50-348,364/92-17).

During the week of July 6 E. Merschoff, Deputy Director, DRS, S. Hoffman, Project Manager, NRR, and F. Cantrell, Section Chief, DRP, RII were on site to tour the plant, meet with licensee managers and resident inspectors, and attend the EDSFI exit interview.

3. Operational Safety Verification (71707) and Fire Protection/ Prevention Program (64704)

The inspectors conducted routine plant tours in accordance with guidance provided by NRC inspection procedure MC71707 to verify licensee requirements and commitments were being implemented.

Inspection tours included review of site documentation interviews with plant personnel and an on-going evaluation of licensee self-assessment.

To ensure that events were properly evaluated, documented and reported, the inspectors reviewed circumstances related to the following events:

a. Fire Main Rupture

At 1:23 p.m. on July 15, a 12 inch fire main east of the secondary access point (SAP) ruptured. A fire main low pressure alarm (55 psig) was received on the main control board in the control room and all diesel driven fire pumps (DDFPs) started. The motor driven fire pump (MDFP) was already running to support fire protection training in progress. At 1:26 p.m., the fire protection tank low level alarm (28' 10") was received. The rupture was discovered by operators and all fire pumps were secured at 1:31 p.m.

A fire isolation was setup and the No. 2 DDFP was started to test the initial isolation boundaries; however, the leak was still evident and the pump was secured. Isolation boundaries were expanded and tested satisfactorily at 2:03 p.m..

Two TS hydrant hose houses were isolated within the leakage boundaries; however, compensatory fire hoses were laid down by 2:20 p.m. The fire protection tank level dropped below the TS limit (25' 6") to 24' during the event; however, level was returned to the TS limit at 2:55 p.m. Approximately 150,000 gallons of water was lost from the rupture. During the event, three cooling tower sprinkler systems and one auxiliary building sprinkler system tripped and were isolated by operators. The No. 1 DDFP was noted to be running hot during the event with approximately 70% of its coolant boiled out. Subsequent investigation revealed a hole in the diaphragm of the coolant solenoid control valve. MWRs were written to affect the above repairs.

Inspectors interviewed the operators and surveyed the rupture site immediately following the event. A special report was submitted to the NRC within 24 hours as required by TSs 3.7.11.1 and 6.9.2. The inspectors discussed the event and the proposed corrective actions with the site fire marshal and the maintenance manager. Southern Company Services conducted a civil engineering analysis of the ground, the fire main piping, and the service water piping to provide excavation guidance in the vicinity of the rupture before beginning repair. Inspectors reviewed the excavation guidance.

The leak was isolated, compensatory hoses were run, and the fire suppression system was restored to operability without delay.

Inspectors observed portions of the excavation and repair efforts. The licensee's activities regarding these efforts were determined to be conducted in an adequate manner.

b. Loss of "2A" SGFP Due To Inadequate Main Oil Pump (MOP) Pressures - Unit 2

On July 4 at 11:45 p.m., while operating at 100 percent power with the SGFP Main Lubricating Oil Pump (MOP) No. 2 in run, bearing oil, cooler oil, and auto stop oil pressures fluctuated over a 15 minute time period and dropped enough to cause an automatic start of the No. 1 standby MOP. No other fluctuations occurred once both MOPs were running. No water was found in the oil reservoir. Amperage readings on the number 2 MOP were at 8 amps with spikes to 40 amps during the pressure oscillations.

On July 5, reactor power was reduced to 70 percent and the standby MOP number 1 was secured at 10:58 a.m. Due to an immediate decrease in auto stop oil pressure when the standby pump was secured, the "2A" SGFP tripped on low auto stop system pressure. Operations personnel immediately reduced reactor power to 60 percent. The "2B" SGFP was able to supply the required feedwater load and operations personnel stabilized power at 64 percent.

Investigation by the licensee revealed that the No. 2 MOP shaft coupling had slipped and that the impeller had dropped enough to create pressure fluctuations. Repairs to the No. 2 pump, and testing of various MOP combinations. The "2A" SGFP was restarted and the unit was returned to 100 percent power operation July 10th.

c. Clearance Tagging Problems Involving Health Physics (HP) Personnel - Unit 2

On April 22, during the recent Unit 2 outage, an HP technician opened the containment sump door without the red hold tag being released and entered the sump with a decontamination team.

The tag was subsequently found on the floor and reported to the shift supervisor by a another HP technician approximately 3 hours later. No radiological releases nor concerns were presented by this event.

On May 21, during performance of an I&C surveillance test on radiation monitor R-11, an I&C technician found the R-11 pump selector handswitch tagged with a hold tag that had been ordered released for tag removal on May 19. The tagging order was initialed as removed.

The shift supervisor was notified and a review of active and inactive tagging orders revealed no other orders for the R-11 or associated system. HP personnel that were supposed to remove the tags on May 19 were interviewed by the licensee and it was concluded that independent verification was not effective. No radiological concerns nor releases were presented by this event.

In both of these events, the individuals involved were counselled and all HP department personnel were presented with specifics of the events in an effort to prevent recurrence. All HP personnel were trained on what to do when unattached or unattended hold tags are found, and were reminded of HP responsibilities to meet the tagging requirements of FNP-0-AP-14, Safety Clearance and Tagging, Section 3.1, 3.12, 3.14, and 6.4.2.

These failures by HP personnel to meet the requirements of AP-14, are identified as non-cited violations and will not be subject to enforcement action because the licensee's efforts in identifying and correcting the violations meet the criteria specified in Section VII.B of the Enforcement Policy. These items are identified as non-cited violation (NCV) 50-364/92-20-02, failure of HP personnel to fully meet safety clearance and tagging requirements.

The results of inspections in this overall area indicate the program was effective in meeting safety objectives. No deviations or other violations were identified in this area.

4. Monthly Maintenance Observation (62703)

The inspectors reviewed various preventative and corrective maintenance activities, in accordance with guidance provided by NRC inspection procedure MC62703, to determine conformance with facility procedures, plant work requests and NRC regulatory requirements.

Portions of the following maintenance activities were observed:

- MWR-249980; Repair of the "2A" SGFP DC oil pump

  Inspectors observed trouble-shooting efforts, assessments and initial repairs of the oil pump.

- MWR-225086; Scaffolding placement over the "1A" BTRS chiller

- MWR-246971; Scaffolding placement over the "2B" BTRS chiller

- MWR-262473; Repair/Replacement of fire main piping

Inspectors observed the scaffolding installation over the "2B" BTRS Chiller heat exchangers and noted that the initial installation was not in full compliance with FNP-0-GMP-60, General Guidelines and Precautions for Erecting Scaffolding. While general industrial safety setups were met, scaffolding to be erected in the vicinity of safety-related equipment must meet other requirements. Requirements were subsequently met by the licensee prior to performance of the repairs.

Inspectors observed portions of the repair of the fire main piping break presented in paragraph 3.a.

Replacement of a 20-foot section of broken pipe and filling of the excavated area with grade "A" backfill was noted.

Repair of the upper areas with gravel and paving is on-going and is scheduled to be complete prior to the next monthly reporting period.

a. Linkage Detached From "1B" RHR Heat Exchanger Discharge Valve - Unit 1 (Follow-up Item)

On April 22, during performance of a surveillance test on the "1B" RHR pump the operator noted that the linkage arm connecting the actuator to the heat exchanger discharge valve had become detached (See Report 50-348,364/92-12, Paragraph 5.b.). Mechanical maintenance installed a new linkage bolt in response to this incident. A records search indicated that this bolt was installed in November, 1986 and its required torque of 45 ft. lbs. was verified in August, 1989. However, licensee representatives stated that it may have been over-torqued when initially installed because the original MWR did not specify the required torque and the craftsman may have used a standard torque (125 ft.lbs.) based on bolt size. A new bolt has been installed with the proper torque. A preventative maintenance item has been initiated to check for proper torque on this bolt every 5 years.

b. SGFP No.1/No.2 Main Oil Pump Leads Switched - Unit 2

On July 7 electrical maintenance (EM) was requested to "de-terminate" the electrical leads for the "2A" SGFP No.2 MOP motor. The No.1 MOP motor leads were also "de-terminated". After maintenance, on July 8, the field leads were swapped between the pumps. Because of this error, the No.1 pump would start when the No.2 pump handswitch was operated and visa-versa.

The licensee determined that personnel error was the root cause of this problem and that 3 journeymen and 3 foremen had opportunities to prevent this problem. They further determined that if anyone would have identified at least one motor lead, the problem could have been avoided. The licensee stated that personnel involved were "working very hard" and they "let their attention to detail degrade". The licensee also flatly stated, in incident report MIR92-016, that "no one questioned" and "no one thought" about identification of MOP motor leads during "de-termination" of leads.

Both motors were "de-terminated" and the field cables rerouted and terminated to the correct motors. Both motors were run and verified to be working per design. EM personnel were given training on the specifics of this incident and ways to prevent recurrence. The EM individuals involved were "coached".

c. Update On William Powell (and Possibly "Other" Vendor) Stainless Steel Valve Disc Holder Problems

On January 31, MESG issued a memorandum, to plant management, describing concerns with William Powell stainless steel valve disc holders. (Refer To Reports 50-348,364/92-02, Paragraph 4.a. and 50-348,364/92-04, Paragraph 4.b.)

Licensee management has further evaluated the possible carbon steel disk holder corrosion problems and has determined, by surveys taken last March 27th, that the problem may be larger than those involving only William Powell valves. At this time, approximately 30 percent of 110 valves evaluated may exhibit similar problems.

The problem with these disk holders in what are suppose to be "stainless steel valves" is very similar to the problem described in NRC Information Notice 90-73. The inspectors are continuing to evaluate disk holder material and corrosion problems and will provide an update on corrective actions in next month's report.

No deviations or violations were identified in this area. The results of inspections in the maintenance area indicate that both operations and maintenance personnel conducted the above tests in accordance with applicable procedures.

5. Monthly Surveillance Observation (61726)

Inspectors witnessed surveillance test activities performed on safety-related systems and components, in accordance with guidance contained in NRC inspection procedure MC61726, in order to verify that such activities were performed in accordance with facility procedures and NRC regulatory and licensee technical specification, requirements.

The following surveillance activities were observed:

o 1-STP-1.0; Operations Daily/Shift Surveillance
2-STP-1.0; Requirements Modes 1, 2, 3, and 4

Inspectors routinely observed unit operators while parameters were monitored, documented and evaluated.

o 1-STP-80.1; Diesel Generator "1B" Operability Test

Inspectors observed operators performing load testing on the D/G, increasing and decreasing electrical loads and maintaining the loads for approximately one hour.

- 1-STP-80.1; Diesel Generator "1-2A" Operability Test

  Inspectors observed operators performing load testing on the D/G, increasing and decreasing electrical loads and maintaining the loads for approximately one hour.

- 1-STP-80.3, "B1F", "B1G" Sequencer Operability Test

  Inspectors noted operator performance for portions of the test and their responses to Agastat performance.

- 2-STP-80.3, "B2F", "B2G" Sequencer Operability Test

  Inspectors noted operator performance for portions of the test and their responses to Agastat performance.

The inspectors evaluated the circumstances related to the following surveillance to ensure that the events were properly evaluated and documented:

- Failure of the D/G Sequencers and Sequencer Agastats

  From July 22 to July 24, licensee surveillance were performed on all automatic load sequencers in order to meet LER 92-09 commitments. The associated Agastat relays failed to meet time intervals specified in STP-80.3, "Sequencer Operability Tests" and in each case, action statements of Technical Specification 3.8.1.1 were entered although the D/Gs were available, they were without operable load sequencers and were technically inoperable.

  On July 23, NRR, Region II, and SNC personnel, held a telephone conference, to discuss the Agastat/sequencer observations and repeated failures of sequencers "B1F", "B1G", "B2F" and "B2G".

  Subsequent and numerous replacements of Agastats and repeat failures of other sequencer Agastats to meet a setpoint acceptance criteria of "+/- 10 percent or 0.5 second, whichever is greater", prompted FNP management, on July 24, to; 1) reestablish a nominal Agastat relay baseline for all Agastats, 2) reset all Agastats to a tighter baseline and to 3) retest all sequencers.

  At the end of this monthly reporting period, only "B1G" sequencer had tested satisfactorily. FNP plans to complete all readjustments on the Agastats and to retest all sequencers.

On July 29, NRR, Region II, and SNC personnel plan to hold another meeting, via telephone conferencing, to discuss any further FNP observations and NRC concerns.

No deviations or violations were identified in this area. Results of inspections in the surveillance area indicate that both operations and maintenance personnel conducted the above tests in accordance with applicable procedures.

6. Response To NRC Initiatives

a. Verification of Plant Records (TI 2515/115)

During this inspection period, the inspectors continued to evaluate the licensee's ability to obtain accurate and complete log readings from non-licensed operators in accordance with guidance contained in temporary instruction TI 2515/115. Only one log record of six initially probable, remained, and it was found to involve a computer error.

b. Drawings For Emergency Preparedness Group Information

Requested system training drawings were sent to designated Region II personnel for upgrading of headquarters emergency preparedness drawings. Revisions to the drawings will be forwarded as they become available to the resident inspectors.

c. Request For Information On Use Of Thermo-Lag Fire Barrier Material (DRP Director Letter - 5/20/92 and NRR Division of Operational Events Letter - 6/24/92)

In response to the above, results of enclosed surveys and instructions were forwarded to Region II personnel in May and, again, in this monthly reporting period. As stated in SNC's response to NRC Bulletin 92-01, no Thermo-lag material is installed at FNP. However, Dow-Corning RTV, Monokote, Flamastic, and Kaowool are used for various FNP fire protection applications. In some areas, to allow for easier routing of electrical cabling, "Nelson-type" penetrations are used.

d. Request For Emergency Diesel Generator Unavailability Data Due To Planned Maintenance During Power Operation and Shutdown Information was obtained from the licensee and forwarded to Region II on July 14th. Although completed forms were to have been sent to Region II by July 8, difficulty in licensee interpretations of requested form information and prior agreements made directly by the licensee to designated NRR personnel, contributed to the delay. Subsequent conversations with designated Region II personnel indicated that the delay did not adversely effect the report sent from region to designated NRR personnel.

No violations or deviations were identified during performance of these response to NRC initiatives.

7. Evaluation of Licensee Self-Assessment Capability - PORC (40500)

Inspectors attended a meeting of the Plant Operations Review Committee (PORC) on July 15. The meeting was chaired by the General Manager - Nuclear Plant and a quorum was present as required by Technical Specification 6.5.1.

The agenda included discussions of a corrective action report that was being used to prepare a response to an NOV for inadequate post maintenance testing (50-364/92-16-02). The agenda also involved discussions of a draft LER, (92-09) for Agastat failures on D/G sequencers criteria.

Most of the meeting was absorbed by the discussion of the corrective action report. Due to other commitments of the PORC members, little in-depth discussion of the draft LER occurred before the meeting was adjourned.

Members appeared to be knowledgeable on the issue, and much of the discussion was uninhibited. However, inspectors noted that most of the PORC focused on wording of the corrective action report rather than its function. Rather than serve as a review organization, the PORC became the originator of the report. Also, the inspectors noted that recommendations made by the PORC to the plant general manager may be biased since he is the chairman of the committee. The inspectors noted that this lack of PORC member independence could prove to be a weakness in FNP's self-assessment capability.

The licensee's self-assessment program, specifically PORC activities, are adequate and no violations or deviations were identified in this area.

8. Emergency Preparedness Notifications and Communications (71707 and 82203)

On July 1 at about 1:30 p.m., the plant shift supervisor was informed by telecommunications, [Southern Company Services (SCS) Network Operations Center (NOC)], personnel that FNP's Emergency Notification Network (ENN) had been returned to service. The plant shift supervisor was unaware that the

ENN had been out of service and he was not assured, after further discussions with telecommunications personnel, that the ENN was available or uninterrupted for greater than 15 minutes, as specified in FNP-0-EIP-26, Offsite Notification.

The Operations Manager and emergency planning (EP) personnel were also unaware that the EOF and TSC ENNs were out of service and one individual from telecommunications thought that only the TSC has been affected. Subsequent discussions between the Operations Manager and telecommunications personnel indicated that the TSC and EOF lines were out of service, but the ENN station located in the shift foreman's office near the control room was operable.

FNP's offsite notification was available and uninterrupted throughout the incident. However, FNP procedure EIP-8, Emergency Communications, Appendix 1, Paragraph 3.4.1, states, (for an expressed purpose of increasing ENN system reliability), that whenever any ENN location is inoperable, a backup form of communications, (a tie SCS teleconferencing network and the ENN circuit or commercial telephone), is to be establisned. Upon recognition of a specific ENN location inoperability, (at any of 15 different ENN locations and this includes the TSC and EOF), a request is to be made for SCS teleconferencing in 5 minutes. Step 3.4.3 of FNP-0-EIP-8 further states that SCS should call back and ensure that the backup ENN connection has been established.

Contrary to the above, telecommunications personnel removed the licensee's EOF and TSC ENN circuits from service without establishment of a backup form of ENN telecommunications and they failed to notify the plant shift supervisor, operations manager and EP personnel of the test prior to working on the system. During testing of any ENN station, that station, or location, is considered to be inoperable.

Telecommunications personnel were told of the importance of such communications and requirements of plant personnel to be informed of any problems as they arise during performance of maintenance. Telecommunications personnel have requested that a change to their procedures be made so that any future ENN or other telecommunications work will be proceeded by contact and discussions with the plant shift supervisor.

The TSC and EOF ENN circuits were returned to service by telecommunications personnel at about 2:45 pm on July 1.

This removal of the EOF and TSC ENN for approximately 1 hour and 15 minutes without establishment of a backup ENN and unknown to the shift supervisor, operations manager and EP personnel, was due to telecommunications personnel error and a failure to adhere to approved written procedures. It is identified as violation 50-364/92-20-01, Removal of the EOF and TSC ENNs without establishment of backup emergency telecommunications.

9. Action on Previous Inspection Findings (92701) and Licensee Event Reports (90712)

(Closed) LER-364/92-01, Manual Reactor Trip Due to a Service Water Leak on an Exciter Cooling Water Line

Inspectors discussed the corrective actions for this event with the maintenance staff. The vendor has changed the procedure for reassembly of the exciter to include specific instructions to facilitate proper mating and assembly of Victaulic couplings. All Unit 2 exciter cooler gaskets were replaced and verified to be leak free during the spring 1992 refueling outage. The Unit 1 gaskets are scheduled to be replaced during the fall 1992 refueling outage. In addition, the maintenance staff has requested that the vendor modify the FNP Modular Performance Program to require that the exciter cooler service water coupling gaskets be replaced during each 54 month exciter inspection. SNC's corrective actions for this event are appropriate. No further NRC inspection is required.

(Closed) LER-364/92-02, Intermediate Range (IR) High Flux Reactor Trip During Shutdown for Refueling Outage

Inspectors reviewed the corrective actions for this event with the operations staff. The unit operating procedures for shutdown have been changed to require operators to verify the IR high flux trip bistables have reset prior to reducing power below 10%. In addition, inspectors reviewed the instrument setpoint data sheets to verify that the IR high flux trip reset setpoints have been raised on both units to increase the probability of the IR trip to reset prior to the P-10 trip re-enable setpoint. Inadequate corrective action for a similar reactor trip in October 1990 contributed to this event. After the October 1990 trip, corrective actions were proposed which would probably have prevented the March 1992 reactor trip. A failure in communication between the operations and reactor engineering departments resulted in not implementing those corrective actions.

Personnel responsible for the failure in communications have been counseled. Additional long term corrective actions for this event are not discussed in the LER, but are discussed in the SNC response to the notice of violation below.

(Closed) Violation 50-364/92-09-01, Inadequate Corrective Actions Failed to Prevent Unit 2 Reactor Trip

Inspectors discussed the long term corrective actions for this event with the technical supervisor and members of his staff. The failure to implement proposed corrective actions for the October 1990 reactor trip was due to personnel error compounded by weaknesses in the FNP administrative procedure for processing incident reports and LERs. The procedure did not provide a way to ensure that commitments for corrective actions were followed through. Training has been conducted to sensitize personnel to the need to track all incident report corrective actions and to provide notification to the groups responsible for implementation. Also, a revision to strengthen the administrative procedure is in process.

In the response to the notice of violation, SNC committed to conduct an investigation to determine if further actions were necessary to account for the flux redistribution impact on the IR instruments due to rod height and core life. As a result of the commitment, an evaluation/root cause analysis was conducted by SNC Nuclear Support and the vendors. The inspectors have reviewed evaluation results/recommendations and found them to be comprehensive. Proposed operational enhancements and preferred options were being reviewed by the plant staff as the inspection period ended. The SNC corrective actions for this event are adequate. Further NRC review is not required.

(Closed) LER-348/91-06, Inadvertent OTDT Trip During Testing

The inspectors reviewed the corrective actions for this event and have noted that the associated wiring was in agreement with the RTD bypass removal design change. A non-cited violation was identified as a result of the original electrical drawings not reflecting the "as-wired" condition of the modification (NCV 348/91-12-01). The inspectors have noted that plant 7300 series protection system drawings have been adequately checked against current FNP controlled drawings and specific discrepancies have been addressed, therefore, this item is closed.

(Closed) LER-348/91-11, Inadequate Test of CCW Sample Cooling Supply Check Valves

The inspectors reviewed the corrective actions for this event and they have noted that the revised procedures appear to have adequately address the previous identified testing deficiencies. The inspectors have also noted that subsequent testing of CCW check valves using these revised procedures allow for better determinations of reverse CCW check valve flow restrictions, therefore, this item is closed.

(Closed) Violation 50-348,364/91-19-01, D/G "1-2A" Inoperable Due To Both Air Start Headers Being Isolated

The inspectors have reviewed the licensee's corrective actions as presented in their reply to the Notice of Violation (NOV). The inspectors have noted that current procedure revisions are incorporating detailed valve lineup and verification guidance. It was also noted that the operations staff has been presented with specific and detailed information regarding directions contained in AP-16, Appendix C, Component Position Determination During Valve Lineups and Performing Tagging Operations Orders. Therefore, this item is closed.

(Closed) LER-348/90-07, Failure of Preaction Fire Protection System Clapper Valves To Trip

The inspectors reviewed the corrective actions for this event and have noted that the current preventative maintenance program has been changed to include periodic replacement of the diaphragms. The inspectors have also noted that improved preaction trip solenoids have been installed since generation of this LER. The number of spurious trips and valve trip failures have been significantly reduced, therefore, this item is closed.

10. Exit Interview

The inspection scope and findings were summarized during management interviews throughout the report period, and on July 28, with the plant manager and selected members of his staff. The inspection findings were discussed in detail. The licensee acknowledged the inspection findings and did not identify as proprietary any material reviewed by the inspectors during this inspection.

The licensee was informed that the items discussed in paragraph 9 were closed.

<u>ITEM NUMBER</u>	<u>DESCRIPTION AND REFERENCE</u>
364/92-20-01 (NOV)	Removal of the EOF and TSC ENNs without establishment of backup emergency telecommunications.
364/92-20-02 (NCV)	Failure of HP personnel to fully meet safety clearance and tagging requirements.

11. Acronyms and Abbreviations

AFW - Auxiliary Feedwater
ALARA - "As Low As Reasonably Achievable"
AOP - Abnormal Operating Procedure
AP - Administrative Procedure
APCO - Alabama Power Company
BOP - Balance of Plant
BTRS - Boron Thermal Regeneration System
CFR - Code of Federal Regulations
CVCS - Chemical and Volume Control System
CCW - Component Cooling Water
CSTS - Condensate Storage Tank System
CS - Containment Spray System
DDFP - Diesel Driven Fire Pump
D/G - Emergency Diesel Generator
DRP - Division of Reactor Projects
DPM - Disintegration Per Minute
ECP - Emergency Contingency Procedure
EIP - Emergency Plant Implementing Procedure
ENN - Emergency Notification Network
EOF - Emergency Operations Facility
EP - Emergency Preparedness
EPA - Environmental Protection Agency
EQ - Environmental Qualifications
ESF - Engineered Safety Features
EWR - Engineering Work Request
F - Fahrenheit
FNP - Farley Nuclear Plant
FSP - Fire Surveillance Procedure
GPM - Gallons Per Minute
I&C - Instrumentation and Controls
IPC - Interim Plugging Criteria
ISI - Inservice Inspection
IST - Inservice Test
LCO - Limiting Condition for Operation
LER - Licensee Event Report
MDFP - Motor Driven Fire Pump
MESG - Maintenance and Engineering Support Group
MOP - Main Oil Pump
MOV - Motor-Operated Valve
MOVATS - Motor-Operated Valve Actuation Testing
MWR - Maintenance Work Request
NCR - Nonconformance Report
NRC - Nuclear Regulatory Commission
NRR - NRC Office of Nuclear Reactor Regulation
NSSS - Nuclear Steam Supply System
OATC - Operator at the Controls
OSHA - Occupational Safety and Health Administration
OTDT - Over-temperature Differential Temperature
PAP - Primary Access Point
PCCV - Positive Closing Check Valve

PCN - Plant Change Notice
PCR - Plant Change Request
PMD - Plant Modifications Department
PORV - Power Operated Relief Valve
PPB - Parts Per Billion
PPM - Parts Per Million
PRT - Pressurizer Relief Tank
PSID - Pressure per Square Inch Differential
PVC - Polyvinyl Chloride
PZR - Pressurizer
RCP - Reactor Coolant Pump
RCS - Reactor Coolant System
RHR - Residual Heat Removal
RPC - Rotating Pancake Coil
RTD - Resistance Temperature Detector
SI - Safety Injection
S/G - Steam Generator
SAER - Safety Audit and Engineering Review
SCS - Southern Company Services
SFO - Shift Foreman - Operating
SGFP - Steam Generator Feedwater Pump
SO - Systems Operator
SFP - Spent Fuel Pool
SNC - Southern Nuclear Operating Company
SOP - Standard Operation Procedure
SPDS - Safety Parameter Display System
SS - Shift Supervisor
SSPS - Solid State Protection System
STP - Surveillance Test Procedure
SWS - Service Water System
TS - Technical Specification
TSC - Technical Support Center
VDC - Voltage Direct Current
WA - Work Authorization