UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
SAM NUNN ATLANTA FEDERAL CENTER
61 FORSYTH STREET, SW, SUITE 23T85
ATLANTA, GEORGIA 30303-8931

January 29, 2007

Southern Nuclear Operating Company, Inc.
ATTN: Mr. R. Johnson
Vice President - Farley
P. O. Box 1295
Birmingham, AL 35201

SUBJECT: JOSEPH M. FARLEY NUCLEAR PLANT - NRC INTEGRATED INSPECTION REPORT 05000348/2006005 AND 05000364/2006005

Dear Mr. Johnson:

On December 31, 2006, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Joseph M. Farley Nuclear Plant, Units 1 and 2. The enclosed integrated inspection report documents the inspection findings, which were discussed on January 3, 2007, with you and other members of your staff.

The inspection examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

This inspection documents two NRC-identified findings of very low safety significance (Green) which were determined to involve violations of NRC requirements. However, because these violations are of very low safety significance and have been entered into your corrective action program, the NRC is treating these two violations as non-cited violations (NCVs) consistent with Section VI.A of the NRC Enforcement Policy. If you contest any NCV in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the United States Nuclear Regulator Commission, ATTN: Document Control Desk, Washington DC 20555-0001; with copies to the Regional Administrator, Region II; the Director, Office of Enforcement, United States Nuclear Regulator Commission, Washington, DC 20555-0002; and the NRC Resident Inspector at the Farley Nuclear Plant.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, its enclosures, and your response (if any) will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of the

NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Scott M. Shaeffer, Chief
Reactor Projects Branch 2
Division of Reactor Projects

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

Enclosure: Inspection Report 05000348/2006005 and
05000364/2006005
w/Attachment: Supplemental Information

cc w/encl: (See page 3)

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cc w/encl:
B. D. McKinney, Licensing
Services Manager, B-031
Southern Nuclear Operating
Company, Inc.
Electronic Mail Distribution

J. R. Johnson
Executive Vice President
Southern Nuclear Operating
Company, Inc.
Electronic Mail Distribution

Bentina C. Terry
Southern Nuclear Operating Company, Inc.
Bin B-022
P. O. Box 1295
Birmingham, AL 35201-1295

State Health Officer
Alabama Department of Public Health
RSA Tower - Administration
201 Monroe St., Suite 700
P. O. Box 303017
Montgomery, AL 36130-3017

M. Stanford Blanton
Balch and Bingham Law Firm
P. O. Box 306
1710 Sixth Avenue North
Birmingham, AL 35201

William D. Oldfield
Quality Assurance Supervisor
Southern Nuclear Operating Company
Electronic Mail Distribution

Distribution w/encl: (See page 4)

Letter to J. R. Johnson from Scott Shaeffer dated January 29, 2007

SUBJECT: JOSEPH M. FARLEY NUCLEAR PLANT - NRC INTEGRATED INSPECTION REPORT 05000348/2006005 AND 05000364/2006005

Distribution w/encl:
K. Cotton, NRR
L. Slack, RII EICS
RIDSNRRDIPMLIPB
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U. S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket Nos.:	50-348, 50-364, 72-42
License Nos.:	NPF-2, NPF-8
Report Nos.:	05000348/2006005 and 05000364/2006005
Licensee:	Southern Nuclear Operating Company, Inc.
Facility:	Joseph M. Farley Nuclear Plant
Location:	Columbia, AL 36319
Dates:	October 1, 2006 - December 31, 2006
Inspectors:	C. Patterson, Senior (Sr.) Resident Inspector E. Crowe, Sr. Resident Inspector J. Baptist, Resident Inspector B. Caballero, Operations Engineer (Section 1R11) B. Schin, Sr. Reactor Inspector (Section 4OA5.3)
Approved by:	Scott M. Shaeffer, Chief Reactor Projects Branch 2 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000348/2006005 and 05000364/2006005; 10/01/2006-12/31/2006; Joseph M. Farley Nuclear Plant, Units 1 & 2, Other Activities.

The report covered a three-month period of inspection by the resident inspectors, a senior reactor inspector, and an operations engineer. Two Green non-cited violations were identified. The significance of most findings is indicated by its color (Green, White, Yellow, or Red) using Inspection Manual Chapter (IMC) 0609, Significance Determination Process (SDP). Findings for which the SDP does not apply may be Green or be assigned a severity level after management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July, 2000.

A. NRC-Identified and Self-Revealing Findings

Cornerstone: Mitigating Systems

- Green. An NRC-identified non-cited violation of 10 CFR 50 Appendix B, Criterion XIV, Corrective Actions, was identified for failure to correct repetitive failures of main steam isolation valves (MSIVs). The April 2006 failure of the three Unit 1 outboard MSIVs to properly operate exhibited similar symptoms to three previous failures which occurred over the period of 2000 to April, 2006. The inspectors identified a number of missed opportunities for the licensee to properly identify and correct the failure mechanisms which led to the most recent failures. The licensee has entered this violation into the corrective action program as CR 2006103043.

  This finding is of greater than minor safety significance because it affected the objectives of the Mitigating Systems cornerstone. It affected the availability and reliability of systems that mitigate initiating events to prevent undesirable consequences and the ability of the outboard MSIVs to close. This finding is of very low safety significance because based on the identified failure mechanisms, the inboard valves were generally independent of the outboard valves performance. The finding had problem identification and resolution cross-cutting aspects related to failure of the licensee to thoroughly evaluate problems such that the resolutions address causes and extent of conditions as necessary. (Section 4OA5 .1)

- Green. An NRC-identified non-cited violation of Unit 2 License Condition C(6), Fire Protection, was identified. Operator actions to isolate the control power for AC power distribution breakers from the effects of a fire in the main control room were included in the fire protection program, but were not implemented in the safe shutdown procedure. The licensee has entered this violation into the corrective action program as CR 2005103658.

  This finding is of greater than minor safety significance because it affected the objectives of the Mitigating Systems cornerstone. It affected the availability and reliability of systems that mitigate initiating events to prevent undesirable consequences and also involved a lack of required fire protection for equipment relied upon for safe shutdown following a fire. The finding is of very low safety significance because of the low frequency of main control room fires that could damage the control cables for electrical breakers in both trains of AC power distribution. (Section 4OA5.3)

B. Licensee-Identified Violations

None

REPORT DETAILS

Summary of Plant Status

Unit 1 operated at or near 100% rated thermal power (RTP) for the inspection period.

Unit 2 operated at or near 100% RTP for the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection

a. Inspection Scope

Impending Adverse Weather Conditions. For the two following weather conditions, the inspectors evaluated implementation of adverse weather preparation procedures and compensatory measures to verify that the applicable portions of procedures FNP-0-AOP-21.0, Severe Weather, and FNP-0-SOP-0.12, Cold Weather Contingencies, were performed.

- tornado warning on November 15
- projected freezing temperatures on November 20

Seasonal Readiness Review. The inspectors evaluated implementation of the licensee's Cold Weather Contingency procedure FNP-0-SOP-0.12 and conditions for entry into the procedure. The inspectors inspected protective coverings on the Main Steam valve rooms grating, on circulating water piping, and heat tracing lines on the condensate storage tanks, reactor makeup water storage tanks, and refueling water storage tanks (RWSTs) to verify these protections for cold weather conditions were functional. The Emergency Diesel Generator (EDG) building was also evaluated to ensure that provisions were implemented to compensate for any known deficiencies. Documents reviewed are listed in the Attachment.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment

a. Inspection Scope

Partial System Walk-downs. The inspectors performed partial walk-downs of the following two systems to verify they were properly aligned when redundant systems or trains were out of service. The walk-downs were performed using the criteria in licensee procedures FNP-0-AP-16, Conduct of Operations - Operations Group, and FNP-0-SOP-0, General Instructions to Operations Personnel. The walk-downs included reviewing the Updated Final Safety Analysis Report (UFSAR), plant procedures and drawings, checks of control room and plant valves, switches, components, electrical power line-ups, support equipment, and instrumentation.

- 1-2A, 1B, 2B, 2C EDGs during maintenance on 1C EDG
- 1A Containment Spray (CS) Pump during 1B CS Pump outage.

Complete Walk-down. The inspectors conducted a complete walk-down of the accessible portions of the 1-2A EDG. The inspectors used licensee procedures FNP-0--SOP-38.0, Diesel Generators , and Function System Description (FSD) document A181005, Diesel Generator System, to verify adequate system alignment of on-service equipment. The inspectors also interviewed personnel and reviewed control room logs, Maintenance Rule (MR) monthly reports, condition reports (CRs), quarterly system health reports, outstanding work orders, and industry operating experience to verify that alignment and equipment discrepancies were being identified and appropriately resolved. Documents reviewed are listed in the Attachment.

b. Findings

No findings of significance were identified.

1R05 Fire Protection

a. Inspection Scope

Fire Area Tours. The inspectors conducted a walk-down of the six fire areas listed below to verify the licensee's control of transient combustibles, the operational readiness of the fire suppression system, and the material condition and status of fire dampers, doors, and barriers. The requirements were described in licensee procedures FNP-0-AP-36, Fire Surveillance and Inspection; FNP-0-AP-38, Use of Open Flame; FNP-0-AP-39, Fire Patrols and Watches; and the associated Fire Zone Data sheets. Documents reviewed are listed in the Attachment.

- Unit 1 and 2 EDG Building, Diesel Generator (DG) 1C, Zone 60
- Unit 1 Auxiliary Building, 1F Safety Related 4160 volt Switchgear, Zone 41
- Unit 2 Auxiliary Building, 2F Safety Related 4160 volt Switchgear, Zone 41
- Unit 2 Auxiliary Building, Component Cooling Water (CCW) Pump and Heat Exchanger Room, Zone 6
- Unit 2 Auxiliary Building, Motor Driven Auxiliary Feedwater Pump (MDAFW) 2A Room, Zone 6
- Unit 2 Auxiliary Building, MDAFW 2B Room, Zone 6

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance

a. Inspection Scope

Annual Review. The inspectors reviewed test results of FNP-0-ETP-4367, Performance Test for Unit 1 & 2 Colt-Pielstick (Large) Diesel Generator Jacket Water Heat Exchangers, for the 1-2A EDG to verify the licensee had adequately identified and resolved any potential heat exchanger deficiencies which could mask degraded performance, common cause heat sink performance problems that could increase risk, and heat sink performance problems that could result in initiating events or affect multiple heat exchangers in mitigating systems. The inspectors also reviewed UFSAR Section 9.5.5 and system design document A-181005, Diesel Generator System, to verify the acceptance criteria for FNP-0-ETP-4367 was appropriate. The inspectors walked down the 1-2A EDG room to verify the material condition of the heat exchangers was not degraded and that any existing deficiencies had been identified. The inspectors also reviewed the licensee's CR database to verify that heat exchanger problems were being identified and resolved. CR 2006109254, SW In-leakage Into The 1-2A EDG Jacket Water System, was reviewed.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification

a. Inspection Scope

Quarterly Resident Review. On November 8, the inspectors observed portions of the licensed operator training and testing program to verify implementation of procedures FNP-0-AP-45, Farley Nuclear Plant Training Program; FNP-0-TCP-17.6, Simulator Training Evaluation Documentation; and FNP-0-TCP-17.3, Licensed Operator Continuing Training Program Administration. The inspectors observed scenarios conducted in the licensee's simulator for a loss of all alternating current power with associated ALERT declaration and loss of 4160 volt bus due to emergency diesel generator failure. The inspectors observed high risk operator actions, overall performance, self-critiques, training feedback, and management oversight to verify operator performance was evaluated against the performance standards of the licensee's scenario. Documents reviewed are listed in the Attachment.

Annual Review of Licensee Requalification Examination Results. On December 15, the licensee completed the requalification annual operating test that was required to be given to all licensed operators pursuant to 10 CFR 55.59(a)(2). The inspector performed an in-office review of the overall pass/fail results of the individual operating tests and the crew simulator operating tests. These test results were compared to the thresholds established in Manual Chapter 609 Appendix I, Operator Requalification Human Performance Significance Determination Process.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness

a. Inspection Scope

The inspectors reviewed the following two issues to verify implementation of licensee procedures FNP-0-87, Maintenance Rule (MR) Scoping Manual; NMP-ES-021, Structural Monitoring Program for the Maintenance Rule; and FNP-0-89, FNP MR Site Implementation Manual; and compliance with 10CFR50.65. The inspectors assessed the licensee's evaluation of appropriate work practices, common cause failures, functional failures, maintenance preventable functional failures, repetitive failures, availability and reliability monitoring, trending and condition monitoring, and system specialist involvement. The inspectors also interviewed maintenance personnel, system specialists, the MR coordinator, and operations personnel to assess their knowledge of the program.

- CR 2006109423, Unit 1 4160V Breaker Function R15-06 Entering (a)1 Criteria
- CR 2005109762, 1D 600 Volt Load Center Return to (a) 2 Criteria

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessments and Emergent Work Control

a. Inspection Scope

The inspectors assessed the licensee's planning and control for the following four planned activities to verify the requirements in licensee procedures FNP-0-ACP-52.3, Guidelines for Scheduling of On-Line Maintenance; NMP-GM-006, Work Management; and FNP-0-AP-16, Conduct of Operations - Operations Group; and the MR risk assessment guidance in 10CFR50.65a(4) were met

- Unit 1, CCW Pump Suction Radiation Monitor (R-17A) failure
- CR 2006109815, Unit 1 Containment Cooler Drain Pot Instrument Malfunction
- Unit 2, Train "A" Solid State Protection System (SSPS) testing, reactor trip breaker testing and unplanned high voltage switchyard testing
- CR 2006110173, Main Steam Support - pin out of clevis

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations

a. Inspection Scope

The inspectors reviewed the following five operability evaluations to verify they met the requirements of licensee procedures FNP-0-AP-16, Conduct of Operations and FNP-0-ACP-9.2, Operability Determination for technical adequacy, consideration of degraded conditions, and identification of compensatory measures. The inspectors reviewed the evaluations against the design bases, as stated in the UFSAR and Functional System Descriptions (FSDs) to verify system operability was not affected.

- CR 2006109254, SW In-leakage Into The 1-2A EDG Jacket Water System
- OD 06-07, 'A' Train Auxiliary Building Return Root Valve Q2P16V625 Leak
- CR 2006109815, Containment Cooler Drain Pots Inoperable
- OD 06-09, 4160 Volt Safety Related Circuit Breakers
- OD 06-10, 2E SW Pump Discharge Expansion Joint

b. Findings

No findings of significance were identified.

1R19 Post Maintenance Testing

a. Inspection Scope

The inspectors reviewed the criteria contained in licensee procedures FNP-0-PMT-0.0, Post Maintenance Test Program, to verify post-maintenance test procedures and test activities for the following five systems/components were adequate to verify system operability and functional capability.

- FNP-1-STP-23.2, 1B CCW Pump Quarterly Inservice Test
- FNP-1-STP-227.13, Vent Stack-Gas Monitor N1D11RE0014 Calibration And Operational Test
- FNP-1-STP-5.0, Full Length Rod operability Test, partial acceptance test for new process computer
- FNP-1-STP-16.2, Containment Spray Pump 1B Inservice Test
- FNP-0-STP-80.1, DG, 1-2A Operability Test

b. Findings

No findings of significance were identified

1R22 Surveillance Testing

a. Inspection Scope

The inspectors reviewed surveillance test procedures and either witnessed the test or reviewed test records for the following four surveillance tests to determine if the tests adequately demonstrated equipment operability and met the TS requirements. The inspectors reviewed the activities to assess for preconditioning of equipment, procedure adherence, and valve alignment following completion of the surveillance. The inspectors reviewed licensee procedures FNP-0-AP-24, Test Control; FNP-0-M-050, Master List of Surveillance Requirements; and FNP-0-AP-16, Conduct of Operations; and attended selected briefings to determine if procedure requirements were met.

Surveillance Tests
- FNP-2-SOP-17.0, App. 4, Main Steam Isolation Valve (MSIV) Functional Test
- FNP-2-STP-80.21, DG 1-2A Remote Shutdown Capability Test

In-Service Tests (ISTs)
- FNP-1-STP-22.16, Turbine Driven Auxiliary Feedwater (TDAFW) Pump Quarterly Inservice Test

Reactor Coolant System (RCS) Leak Detection
- FNP-1-STP-9.0, RCS Leakage

b. Findings

No findings of significance were identified

1R23 Temporary Plant Modifications

a. Inspection Scope

The inspectors reviewed the following temporary modification (TM) and associated 10CFR50.59 screening criteria against the system design bases information and documentation and the licensee's temporary modifications procedure FNP-0-AP-8, Design Modification Control. The inspectors reviewed implementation, configuration control, post-installation test activities, drawing and procedure updates, and operator awareness for this TM.

- TM S062942701, 1B EDG room intake louvers blocked open.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA2 Identification and Resolution of Problems

.1 Daily Review

As required by Inspection Procedure 71152, "Identification and Resolution of Problems," and to help identify repetitive equipment failures or specific human performance issues for follow-up, the inspectors performed a daily screening of items entered into the licensee's corrective action program. This review was accomplished by reviewing daily hard copy summaries of CRs and by reviewing the licensee's electronic CR database.

.2 Semi-Annual Trend Review

a. Inspection scope

As required by Inspection Procedure 71152, Identification and Resolution of Problems, the inspectors performed a review of the licensee's Corrective Action Program (CAP) and associated documents to identify trends that could indicate the existence of a more significant safety issue. The inspectors' review focused on CRs associated with component vibration and component failures which were likely caused by excessive vibration. The review also considered the results of the daily inspector CAP item screening discussed in Section 4OA2.1, licensee trending efforts, and licensee human performance results. The inspectors reviewed the licensee quarterly trend reports for April 2006 and July 2006, selected CR's, Maintenance Rule (a)(1) list, equipment health reports, and quality assurance reports to identify issues not recognized by the licensee. The inspectors compared and contrasted their results with the results contained in the licensee's quarterly trend reports. Corrective actions associated with a sample of the issues identified in the licensee's trend report were reviewed for adequacy.

b. Findings and Observations

No findings of significance were identified. The inspectors noted the licensee had identified structural failures in the AFW System and the Main Steam System. The licensee attributed the failures in the AFW System to high vibrations caused by excessive recirculation flow during planned surveillances of the TDAWF pump. Specifically, the structural failures resulted in cracked recirculation piping in Unit 1 twice in 1978 and once in 2005. Similar structural failures of Unit 2 recirculation piping occurred in 1980, 1982, 1997, and June 2006. Following the June 2006 failure, the licensee performed a root cause investigation and identified high vibration levels on much of the auxiliary feedwater piping as the primary contributor for the problems experienced on the system miniflow and recirculation piping. The licensee's root cause evaluation recommended the licensee perform a vibration analysis to capture vibration data to be utilized in the development of a plant modification for additional pipe supports.

The licensee implemented a snubber reduction program resulting in the removal of pipe snubbers in the Unit 2 main steam valve room. Following snubber removal, the licensee identified increased vibration of the Unit 2 main steam lines in September, 1996. Because of this coincidence, the licensee performed a vibration study in 2001 whose specific objectives were to determine the cause of the failures in the main steam supports and determine the robustness of the system for the remaining life of the plant. The study concluded the root cause of the support failures was high cycle fatigue resulting from main steam line vibration. The vibration was caused by flow disturbance in the main steam line header and turbine inlet. The study also concluded piping and supports are acceptable for the vibrations analyzed in May, 2001 and design improvements on the supports inside containment are judged to be robust and expected to provide adequate support. The study recommended periodic inspection inside containment, visual inspections in the main steam valve room, and additional monitoring following inspection at the next refueling outage. During 2006, the Main Steam System experienced the set screws unthreading and falling from the manual actuator cap for the 2C main steam isolation valve resulting in the cap bouncing on top of the valve, damage to the upper limit switch arm of the downstream 2A main steam isolation valve, and damage to the main steam line support for the south header downstream of the transition header of the main steam lines.

The inspectors noted the licensee has three safety related pumps on an increased vibration monitoring frequency due to exceeding their administrative threshold vibration limits . Two of the pumps are centrifugal charging pumps (High Head Safety Injection) and have been on increased monitoring for approximately one year. The third pump is the Unit 1 “A” SW Pump which has also been on increased monitoring for approximately one year. The Unit 1 “A” and Unit 2 “C” centrifugal charging pumps are demonstrating an increased vibration trend on the pump bearings. Current vibration data indicates that both pumps are slightly above 50 percent of the level where the pump would be considered inoperable. The licensee plans to perform alignments on these pumps in January and March, 2007 respectively. The Unit 1 “A” SW Pump motor bearings are demonstrating relatively stable vibration trends. The licensee believe this data indicates that baseline vibration levels were established prior to adequate “run in” of this pump. The licensee’s vibration specialist plan on maintaining this pump on increased vibration monitoring until the new baseline data is obtained.

The inspectors concluded the licensee is generally identifying vibration issues and entering them into their correction action process at the appropriate threshold. However, the inspectors will continue to monitor these areas as the licensee is still gathering relevant data and has not reached a conclusion on proposed design change packages to dampen/eliminate vibration from the Main Steam System and Auxiliary Feedwater Mini-flow and Recirculation piping. No current operability issues were identified.

The inspectors verified previous vibration issues inside containment have not reappeared; however, did note an increase in MS component failures (including the MSIVs) over the past year. In addition, detailed evaluations of the MS component failures could have been more rigorous. Enhanced engineering monitoring of the MS system would have resulted in a more proactive approach to the early identification of problems.

4OA5 Other Activities

.1 (Closed) Unresolved Item (URI) 05000348/2006009-001, Repetitive Main Steam Isolation Valve (MSIV) Closure Failures

a. Inspection Scope

The inspectors reviewed the history of MSIV failures which exhibited similar symptoms to the Unit 1 MSIV failures on April 8, 2006. The review included pertinent corrective action program documents, maintenance work requests, and interviews with cognizant engineers. The licensee's final root cause evaluation for CR 2006103043 has been completed and reviewed by the inspectors.

b. Findings

Introduction: A Green NRC identified NCV of 10CFR50 Appendix B, Criterion XVI was identified for inadequate corrective action. Specifically, the inspector identified three prior opportunities for the licensee to identify and correct conditions that would cause an MSIV to fail to operate when demanded.

Description: During Main Steam Isolation Valve (MSIV) testing in April 2006, three of the MSIV's failed to partially close during testing. The licensee entered CR 2006103043 into their corrective action program following the April 2006 failures and performed a root cause investigation. This root cause evaluation determined that the cause for the MSIVs failures was an increase in total friction from multiple sources originating from valve re-construction procedures, component clearance tolerances, and packing installation methods. The root cause team also identified that these sources of friction were all amplified by the severe turbulent environment in which the downstream MSIV's exist. The inspectors performed a review of the MSIV maintenance history and identified several performance problems with the downstream MSIVs. Based on historical evidence and the licensee's initial root cause conclusions from the 2006 root cause team, the inspectors determined the licensee had experienced three MSIV failures since 2000 which exhibited symptoms similar to the failures in April 2006. Table 3 summarizes the similar MSIV failures.

Table 3: Recent Similar MSIV Failures at FNP

Unit 2/ 3370A	11/00	Would not move to test position.	Friction From Dirty Main Actuator Stem.
Unit 2/ 3370A	05/01	Would not fully stroke.	Friction due to Misalignment of Indicator Plate.
Unit 1/ 3370B&C	05/02	Would not move to test position	Valve Friction and Variances in Air Actuator Pressure.

The specifics of these examples are discussed below.

- On November 3, 2000, CR 2000005687 was written due to a failure of U2 MSIV 3370A. The licensee suspected binding friction between the MSIV yoke bushing and shaft. Lubrication was applied and the test stroke was re-performed with successful results. The licensee performed evaluations, on January 5, 2001 and January 19, 2001, which concluded that the main actuator was stuck due to the accumulation of dirt on the actuator stem. The cleaning and lubricating of the stem allowed the MSIV to successfully stroke in subsequent attempts. This conclusion of the root cause investigation of CR 2006103043 performed in April 2006 indicated that 2001 root cause conclusion was not complete. The 2006 root cause investigation indicated that there was sufficient margin to both open (main actuator) and close (disc weight and spring tension) the MSIV in the presence of dirty actuator stems. The inspectors concluded that the November 2000 CR was the first key opportunity for the licensee to fully investigate and resolve the potential problem.

- On May 8, 2001, CR 2001001155 was written for a failure of MSIV 3370A to fully stroke. The Maintenance department concluded that the MSIV indicator plate was providing additional friction due to thermal expansion and preventing the MSIV from fully closing. Maintenance personnel adjusted the indicator plate, and applied lubrication to the yoke bushing and main actuator assemblies. The MSIV was stroked satisfactorily and the above condition report was closed due to actions taken. This is contrary to the conclusion of the root cause investigation of CR 2006103043 performed in April 2006. This root cause investigation indicated that the MSIV shaft would come in contact with the MSIV indicator plate, but that the friction available from the surface area contact would not be individually significant enough to prevent MSIV closure. The inspectors concluded the original evaluation for CR 2001001155 was inadequate, in that, an unlikely root cause was determined and further investigations were not made. The inspectors concluded this was the second key opportunity for the licensee to fully investigate and resolve the potential problem

- On May 4, 2002, CR 2002001026 was written due to the failure of Unit 1 MSIVs 3370B and 3370C to stroke. WOs were implemented and, contrary to previously identified guidance dating back to 2000, maintenance personnel lubricated MSIV stems using WD-40. The MSIVs were retested satisfactorily and the licensee believed that difficult valve operation originated with unnecessary wear from the stroke test itself. Licensee conclusions from the root cause investigation of CR 2006103043 indicated the stroke test was beneficial in maintaining free movement and the stroke test should not have been eliminated. The licensee has reinstated this partial stroke test on both operating units MSIVs at a quarterly periodicity to gather data and aid in determining long term operability throughout the current operating cycles. The inspectors concluded this was the third key opportunity for the licensee to fully investigate and resolve the potential problem.

<u>Analysis</u>. The inspectors concluded that the licensee failed to take corrective actions to prevent recurrence of safety related MSIV failures due to mechanical binding. This is based on the licensee's history of MSIV failures; the information available in the maintenance history of the MSIVs; the previously instituted corrective actions; and the

availability of applicable industry and vendor experience. These inadequate corrective actions, which resulted in the failures of MSIVs Q1N11HV3370A (3370A), Q1N11HV3370B (3370B), and Q1N11HV3370C (3370C) were considered to be a performance deficiency.

The finding was more than minor since it affected the Mitigating Systems Cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). The Main Steam system is required to mitigate the consequences of a Main Steam Line Break (MSLB) Outside Containment and Steam Generator Tube Rupture (SGTR) accidents by closure of the appropriate MSIVs. A Phase 1 screening, in accordance with Inspection Manual Chapter (IMC) 609, Appendix A, was performed and identified that the finding represented an actual loss of safety function for greater than its allowed Technical Specification Outage Time. This conclusion required a Phase 2 risk significance estimation and justification which yielded an analysis of Green risk significance. A Phase 3 risk significance estimation was requested to fully characterize the impact of the multiple MSIV failures on plant risk.

A regional Senior Reactor Analyst (SRA) performed a Phase 3 Evaluation. Based upon this evaluation the performance deficiency was characterized as of very low safety significance (Green). The most critical assumption in the evaluation was that the inboard Main Steam Isolation Valves failure to close rates were generally independent of the outboard valves' performance. This assumption was based upon the historical performance of all the Main Steam Isolation Valves, as reflected in work orders over approximately twenty years. This historical information clearly indicated that an additional failure mechanism, (high vibration and presence of turbulent flow) not present with the inboard valves, was contributing to the much higher failure rate of the outboard valves. A site specific individual and common cause failure probability was developed for the inboard valves that excluded the outboard valves' history. These values were used in the probabilistic risk assessment model that was used for the Phase 3 evaluation. The dominant accident sequence involved a Steam Generator Tube Rupture and, a failure to isolate the faulted generator through the performance deficiency (failing the outboard Main Steam Isolation Valves) and the random failure of the non-affected generators' inboard isolation valves. Secondary side heat removal and High Pressure Injection was successful but, the replenishment of the Refueling Water Storage Tank was not successful. Consequently, core damage ensued. This finding was also determined to have had crosscutting aspects associated with problem identification and resolution. Specifically, in the aspect of evaluating problems, extent of conditions, properly classifying, prioritizing, and evaluating for operability and reportability conditions adverse to quality.

<u>Enforcement</u>. On April 8, 2006, Unit 1 Main Steam Isolation Valves Q1N11HV3370A (3370A), Q1N11HV3370B (3370B), and Q1N11HV3370C (3370C) failed to properly operate due to binding of the mechanical components in each of the valve's internals. 10 CFR Part 50, Appendix B, Criterion XVI, requires that measures shall be established to assure that conditions adverse to quality, such as failures and malfunctions, are promptly identified and corrected. In the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and

corrective action taken to preclude repetition. Contrary to this requirement, the licensee has experienced multiple similar valve failures over it's operating history, but has failed to identify, correct, and preclude repetition of a significant condition adverse to quality. This violation, which was determined to have very low safety significance and was entered into the licensee's corrective action program as CR 2006103043, is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000348/2006005-001, Inadequate Corrective Actions for Main Steam Isolation Valve Failures.

.2 (Closed) NRC Temporary Instruction (TI) 2515/169, Mitigating Systems Performance Index(MSPI) Verification

a. Inspection Scope

During this inspection period, the inspectors completed a review of the licensee's implementation of the Mitigating Systems Performance Index (MSPI) in accordance with the guidance provided in TI 2515/169. The inspectors examined surveillances that the licensee determined would not render the train unavailable for greater than 15 minutes or during which the system could be promptly restored through operation action and therefore, are not included in unavailability calculations. As part of this review, the recovery actions were verified to be uncomplicated and contained in written procedures. On a sample basis, the inspectors reviewed operating logs, MR information, corrective action program documents, and surveillance procedures to determine the actual time periods the MSPI systems were not available due to planned and unplanned activities. The results were then compared to the baseline planned unavailability and actual planned and unplanned unavailability determined by the licensee to ensure the data's accuracy and completeness. These documents were also reviewed to ensure MSPI component unreliability data determined by the licensee identified and properly characterized all failures on monitored components. The unavailability and unreliability data were then compared with performance indicator data submitted to the NRC to ensure it accurately reflected the performance history of these systems.

b. Findings and Observations

No findings of significance were identified. The licensee accurately documented the baseline planned unavailability hours, the actual unavailability hours and the actual unreliability information for the MSPI systems. No significant errors in the reported data were identified, which resulted in a change to the indicated index color. No significant discrepancies were identified in the MSPI basis document which resulted in: (1) a change to the system boundary, (2) an addition of a monitored component, or (3) a change in the reported index color.

.3 (Closed) Unresolved Item (URI) 05000348,364/2005006-002, Fire Procedure Failed to Ensure that AC Power Would Be Available

a. Inspection Scope

The inspectors performed an in-office review of the licensing basis for mitigation of control room fires.

b. Findings

Introduction. A Green NRC- identified non-cited violation of Unit 2 License Condition C (6), Fire Protection, was identified. Operator actions to isolate the control power for AC power distribution breakers from the effects of a fire in the main control room were included in the fire protection program but were not implemented in the safe shutdown procedure. Consequently, fire damage to the control cables in the main control room could potentially cause a loss of AC power to equipment that was relied on to mitigate the fire.

Description. As described in Inspection Report 05000348,364/2005006, the inspectors found that procedure FNP-2-AOP-28.2, "Fire in the Control Room," Rev. 20, did not include local manual actions to isolate the control power for both trains of safety-related AC power distribution breakers from the main control room. However, those actions were included in the licensee's fire protection program. The fire protection program was described in the Farley Units 1 and 2, 10 CFR Part 50, Appendix R, Fire Protection Program, Alternative Shutdown Capability, Rev. 14. The program included operator actions to be performed to mitigate a severe fire in the main control room. It included actions to operate 50 local control power transfer switches to isolate the control power for electrical distribution breakers for both units from the main control room. However, those actions had not been implemented into procedure FNP-2-AOP-28.2. Consequently, a severe fire in the main control room could potentially cause breakers in both safety-related trains of AC power to fail open, resulting in a loss of AC power to equipment that was relied upon to mitigate the fire. In response to this concern, the licensee promptly entered the issue into the corrective action program in CR 2005103658 and revised procedure FNP-2-AOP-28.2 to include the operator actions of concern.

Analysis. This finding is of greater than minor safety significance because it affected the objectives of the Mitigating Systems Cornerstone of Reactor Safety. It affected the availability and reliability of systems that mitigate initiating events to prevent undesirable consequences and also involved a lack of required fire protection for equipment relied upon for safe shutdown following a fire. The finding adversely affected safe shutdown in that a fire in the main control room electrical control board could potentially spread from one vertical section of the control board to an adjacent section and damage control cables for electrical breakers in both trains of AC power distribution. Consequently, the fire could cause breakers in both safety-related trains of AC power to fail open, resulting in a loss of AC power to equipment that was relied upon to mitigate the fire.

Because the finding affected post-fire safe shutdown, represented a high degradation, and had a duration of more than 30 days, a Phase 2 analysis was required. The main control room was too large to support development a hot gas layer and none of the fire barriers between the main control room and other fire areas were known to be degraded. Therefore, only a fire damage state (FDS) 1 fire scenario was considered. Because the fires of concern involved two adjacent vertical sections of the electrical control board (out of approximately fourteen sections), the associated fire frequency was determined to be 3.57 E-4 per year. Sandia National Laboratories (SNL) fire tests of vertical control cabinets with thermoset cables could produce heat release rates (HRR) of 200 KW which would breach a steel barrier between two vertical sections of a control cabinet and damage cables on the other side of the barrier within about 10 minutes if the cables are touching the barrier. Since the 200 KW HRR fire would occur about 10% of the time, a severity factor of 0.1 was used. With detection time assumed to be less than one minute, the time available after detection but before damage was nine minutes. With no installed automatic suppression, the resulting overall probability of non-suppression was 0.11. The revised fire frequency was 3.93 E-6.

The inspectors evaluated various combinations of two or more hot shorts and spurious opening of breakers in the two trains of AC power distribution. All 4KV and 600V AC breakers controlled from the electrical control board that could adversely affect safe shutdown were considered. (e.g., one combination involved spurious opening of the two normal power supply breakers to the two safety-related 4KV busses and failure of the two EDG output breakers that feed those busses.) No credit was given for operator recovery actions to restore power because there was no procedure to locally isolate breaker control power and manually reposition breakers. After consideration of all combinations of breaker failures of concern to plant safe shutdown, the overall change in core damage frequency was calculated to be 8.96 E-7 per year. Because that frequency was less than 1.0 E-6, the risk was considered to be of very low significance (Green).

<u>Enforcement</u>. Joseph M. Farley Unit 2 License Condition C(6), Fire Protection, requires that Southern Nuclear implement and maintain in effect all provisions of the approved fire protection program as described in the FSAR for the facility and as approved in the Fire Protection Safety Evaluation Reports. The licensee may make changes to the approved fire protection program without prior approval of the Commission only if those changes would not adversely affect the ability to achieve and maintain safe shutdown. The fire protection program included local manual operator actions to isolate the control power for AC power distribution breakers from the effects of a fire in the main control room. Contrary to the above, local manual operator actions to isolate the control power for AC power distribution breakers from the effects of a fire in the main control room were not implemented in procedure FNP-2-AOP-28.2, Fire in the Control Room, Rev. 20. Because the finding is of very low safety significance and has been entered into the licensee's corrective action program as CR 2005103658, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy and is identified as NCV 05000364/2006005-002, Fire Procedure Failed to Ensure that AC Power Would Be Available.

4OA6 Meetings, Including Exit

On January 3, 2007, the inspectors presented the inspection results to you and other members of your staff who acknowledged the findings. The inspectors confirmed that proprietary information was not provided or examined during the inspection.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee personnel
W. L. Bargeron, General Manager
W. R. Bayne, Performance Analysis Supervisor
S. H. Chestnut, Engineering Support Manager
P. Harlos, Health Physics Manager
L. Hogg, Security Manager
J. Horn, Training and Emergency Preparedness Manager
J. R. Johnson, Vice President - Farley
T. Livingston, Chemistry Manager
B. L. Moore, Maintenance Manager
W. D. Oldfield, Quality Assurance Supervisor
J. Swartzwelder, Work Control Superintendent
R. J. Vanderbye, Emergency Preparedness Coordinator
R. Wells, Operations Manager
T. L. Youngblood, Site Plant Support Manager

NRC personnel
S. Shaeffer, Chief, Branch II, Division of Reactor Projects

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

05000348/2006005-001	NCV	Inadequate Corrective Actions for Main Steam Isolation Valve (MSIV) Failures (Section 4OA5.1)
05000364/2006005-002	NCV	Fire Procedure Failed to Ensure that AC Power Would Be Available (Section 4OA5.3)

Closed

05000348/2006009-001	URI	Repetitive Main Steam Isolation Valve (MSIV) Closure Failures (Section 4OA5.1)
05000348,364/2005006-002	URI	Fire Procedure Failed to Ensure that AC Power Would Be Available (Section 4OA5.3)
05000348/2515/169	TI	Mitigating Systems Performance Index Verification (Section 4OA5.2)

LIST OF DOCUMENTS REVIEWED

Section 1R01: Adverse Weather Protection
FNP-0-SOP- 0.12, Cold Weather Contingencies
FNP-0-STP-63.5, HVAC Verification For Diesel Generator Building
FNP,1/2-EMP-1383.01, Freeze Protection Inspections
UFSAR Section 9.4.7, Diesel Generator Building
UFSAR Section 6.3, Emergency Core Cooling System
CR 2006109633, 1B EDG Thermostat
CR 2006109690, U2 RMWST Insulation

Section 1R04: Equipment Alignment
Technical Specification 3.8.1, AC Sources - Operating
FNP-0-SOP-38.0, Diesel Generators
T.S. 3.8.1, AC Sources - Operating
Functional System Description A-181005, Diesel Generator System

Section 1 R05: Fire Protection
Plant Drawings:
A-508650, Sheet 32 Revision 2
A-508651, Sheet 1 Revision 6
A-508651, Sheet 2 Revision 1
A-508651, Sheet 6 Revision 3
A-509018, Sheet 12 Revision 3
A-509018, Sheet 14 Revision 2
A-509018, Sheet 30 Revision 15
A-509018, Sheet 30A Revision 1

Section 1R11: Licensed Operator Requalification
FNP-1- ECP- 0.0, Loss of All AC Power
FNP-1- EEP - 0.0, Reactor Trip or Safety Injection
FNP-1- AOP - 5.0, Loss of A or B Train Electrical Power

Section 4OA2: Identification and Resolution of Problems
Condition Reports
2004102349, 2005103994, 2005112080, 2006107519, 2004103198, 2005104355, 2005112353, 2006107225, 2004105068, 2005106752, 2005112553, 2006108306, 2004105342, 2005106828, 2005112747, 2006108431, 2004107203, 2005108231, 2006100010, 2006108516, 2004107244, 2005100565, 2005108592, 2006100378, 2006108602, 2005100309, 2005108593, 2006100637, 2006109261, 2005108594, 2006102281, 2006109819, 2005101484, 2005110018, 2006105386, 2006109843, 2005103552, 2005112004, 2006106639, 2006110173, 2005103553, 2005112073, 2006107168, 200611034
FNP-1-STP-4.1, “1A Charging Pump Quarterly Inservice Test”, Revision 45
FNP-1-STP-24.1, “1A, 1B, and 1C Service Water Pump Quarterly Inservice Test”, Revision 52
FNP-2-STP-4.3, “2C Charging Pump Quarterly Inservice Test”, Revision 39

Section 4OA5: Other Activities

FNP-0-M-151.0 NRC Mitigating Systems Performance Index (MSPI) Basis Document Joseph M. Farley Nuclear Plants Units 1 and 2, Version 2
FNP-0-STP-80.1 Diesel Generator 1-2A Operability Test, Revision 46
FNP-0-STP-80.6 Diesel Generator 1-2A 24 Hour Load Test, Revision 24
FNP-1-STP-80.20 Diesel Generator 1-2A 1000 KW Load Rejection Test, Revision 9
FNP-1-STP-22.8 AFW Inservice Valve Exercise Test, Revision 19
FNP-2-STP-45.5 RHR Cold Shutdown Valves Inservice Test, Revision 8
MSPI Derivation Report Unit 1 Emergency AC Power System June 2006
MSPI Derivation Report Unit 1 Heat Removal System (Auxiliary Feedwater {AFW}) June 2006
MSPI Derivation Report Unit 1 High Head Safety Injection June 2006
MSPI Derivation Report Unit 1 Cooling Water Support Systems June 2006
MSPI Derivation Report Unit 2 Emergency AC Power System June 2006
MSPI Derivation Report Unit 2 Heat Removal System (Auxiliary Feedwater {AFW}) June 2006
MSPI Derivation Report Unit 2 High Head Safety Injection June 2006
MSPI Derivation Report Unit 2 Cooling Water Support Systems June 2006
MSPI Derivation Report Unit 1 Emergency AC Power System July 2006
MSPI Derivation Report Unit 1 Heat Removal System (Auxiliary Feedwater {AFW}) July 2006
MSPI Derivation Report Unit 1 High Head Safety Injection July 2006
MSPI Derivation Report Unit 1 Cooling Water Support Systems July 2006
MSPI Derivation Report Unit 2 Emergency AC Power System July 2006
MSPI Derivation Report Unit 2 Heat Removal System (Auxiliary Feedwater {AFW}) July 2006
MSPI Derivation Report Unit 2 High Head Safety Injection July 2006
MSPI Derivation Report Unit 2 Cooling Water Support Systems July 2006
NEI-99-02 Regulatory Assessment Performance Indicator Guideline, Revision 4
Unit 1 Service Water - MSPI Run Time/Demand Baseline Data
Unit 2 Service Water - MSPI Run Time/Demand Baseline Data
Selected Control Room Logs, January 2004 through September 2006