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

May 24, 2006

Southern Nuclear Operating Company, Inc.
ATTN: Mr. H. L. Sumner
Vice President - Hatch Project
P. O. Box 1295
Birmingham, AL 35201-1295

SUBJECT: EDWIN I. HATCH NUCLEAR PLANT - NRC SPECIAL INSPECTION REPORT 05000366/2006012

Dear Mr. Sumner:

On April 12, 2006, the U.S. Nuclear Regulatory Commission (NRC) completed a Special Inspection at your Hatch Unit 2 facility. On April 5, 2006, the Unit 2 turbine tripped, with a subsequent reactor scram. Because automatic steam sealing equipment was isolated, lowering condenser vacuum resulted in a loss of the only operating feedwater pump. These events were evaluated by the NRC in accordance with Management Directive 8.3, "NRC Incident Investigation Program," and a Special Inspection was initiated because the event involved significant unexpected system interactions, and the risk evaluation value exceeded the minimum required for a Special Inspection.

The enclosed report documents the inspection results, which were discussed on April 12, April 21 and April 27, 2006, with Mr. Dennis Madison and other members of your staff. The determination that the inspection would be conducted was made by the NRC on April 6, 2006, and the inspection started on April 10, 2006.

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.

Based on the results of this inspection, no findings of significance were identified.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, 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

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

Sincerely,

/RA/

Charles Casto, Director
Division of Reactor Projects

Docket No.: 50-366
License No: NPF-5

Enclosure: Inspection Report 05000366/2006012
w/Attachments

Attachments: 1. Supplemental Information
2. Sequence of Events

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

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Distribution w/encl: (See page 4)

Letter to Mr. H. L. Sumner from Charles A Casto dated May 18, 2006.

SUBJECT: EDWIN I. HATCH NUCLEAR PLANT - NRC SPECIAL INSPECTION REPORT 05000366/2006012

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U. S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket No.:	05000366
License Nos.:	NPF-5
Report No.:	05000366/2006012
Licensee:	Southern Nuclear Operating Company, Inc.
Facility:	Edwin I. Hatch Nuclear Plant
Location:	P.O. Box 2010 Baxley, Georgia 31515
Dates:	April 10 through April 12, 2006
Inspectors:	D. Simpkins, Senior Resident Inspector (Lead Inspector) N. Garrett, Senior Resident Inspector
Approved by:	Charles Casto, Director Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000366/2006-012; 04/10/2006 - 04/12/2006; Edwin I. Hatch Nuclear Plant, Unit 2; Special Inspection

This Special Inspection was conducted by two Region II Senior Resident Inspectors using Inspection Procedure 93812 to investigate the of the loss of all normal feedwater. 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

No findings of significance were identified.

B. Licensee-Identified Violations

None.

Enclosure

REPORT DETAILS

EVENT OVERVIEW

On April 5, 2006, while calibrating the megavars recorder for the Unit 2 turbine generator, a power-load imbalance signal was generated from maintenance activities which resulted in a turbine trip/reactor scram. When both recirculation pumps automatically tripped by design and eight safety relief valves opened, reactor water level increased to above the Reactor Feedwater Pumps (RFP) trip setpoint, and both RFPs tripped. When reactor water level sufficiently lowered, the operators restarted the 2A RFP. However, because of reliability problems in the automatic pressure regulator portion of the steam seal system, sealing steam was being controlled manually. Because the manual control valve had not been adjusted properly, there was insufficient sealing steam to the turbine, which caused condenser vacuum to decrease, and the 2A RFP tripped again because of low condenser vacuum. Operators were eventually able to restore sealing steam in automatic control and stabilized condenser vacuum before the automatic isolation of the bypass valves was reached. The operators manually initiated RCIC and HPCI to restore water level.

Special Inspection Team Charter

Based on the criteria specified in Management Directive 8.3, "NRC Incident Investigation Procedures," a Special Inspection was initiated in accordance with NRC Inspection Procedure (IP) 93812, "Special Inspection." The objectives of the inspection are listed below and are addressed in the following sections.

(1) Develop a sequence of events including applicable management decision points from the time of the previous Unit 2 outage through recovery and unit restart from the event.

(2) Review licensee documents to assess if the licensee knew that a loss of condenser vacuum would occur after a turbine trip without operator action. Specifically, assess the following areas:

- Operational Decision Making
- Operator Workaround assessment
- Impact on Maintenance Rule implementation

(3) Assess any corrective action the licensee took prior to the event to address the steam seal control problem and determine if the actions were appropriate and timely.

(4) Assess operating procedures and operator training concerning this scenario and determine if the procedures and training were adequate for operators to compensate for the lack of the automatic seal steam control function.

(5) Review post-scram cooldown data and determine if operator actions to control cooldown response were within procedural guidance.

(6) Collect data necessary to support completion of the significance determination process.

(7) Review this event for generic safety implications.

4. OTHER ACTIVITIES

4OA3 Event Followup (IP 93812)

.1 Develop a sequence of events and assess corrective actions (Objectives 1, 3 and 6)

a. Inspection Scope

The inspectors developed a detailed sequence of events leading up to the event based on the licensee's sequence of events, a review of plant logs, completed work orders and condition reports. The sequence of events (Attachment 2) includes a timeline of observations, corrective actions and work activities that occurred since the previous refueling outage to the time of the event.

b. Findings and Observations

The steam seal system had a history of operational issues prior to the previous refueling outage. Because the system is effectively only in operation to 30% power (above 30%, the steam sealing function is provided by normal steam leakage from the turbine), few opportunities existed to identify issues and repair the system. However, those opportunities available were appropriately captured and entered into the corrective action program.

.2 Review licensee documents to assess if the licensee knew that a loss of condenser vacuum would occur after a turbine trip without operator action (Objective 2)

a. Inspection Scope

The inspectors reviewed post-scram interviews, condition reports, and operator logs as well as conducted interviews to determine the extent to which the licensee realized a loss of condenser vacuum would occur after a turbine trip without operator action.

b. Findings and Observations

1. Operational Decision Making

The licensee did not consider the automatic steam seal system isolation as applicable to the Operational Decision Making Issue evaluation process, since the limits of the equipment degradation had been reached when the automatic system had been taken out of service via caution tags (i.e., it could not get any worse). Therefore, there were no clear-cut management decision points using this process.

2. Operator Workaround assessment

The licensee did not consider the isolated automatic pressure control portion of the steam seal system to be an operator workaround. Therefore, the condition of the system did not receive the attention and resources which could have been available had

it been properly categorized. Additionally, the operators were not necessarily as cognizant of the issue as they could have been had this been an operator workaround.

This issue was determined to not be a finding because the licensee was not specifically committed to using the operator workaround program.

3. Impact on Maintenance Rule implementation

The Maintenance Rule Scoping Manual Performance Criteria defined a functional failure for the Steam Seal system as a failure which results in a turbine trip or down power of greater than 20%, and furthermore stated this criteria would effectively monitor the performance of the system. However, the inspectors noted such a high threshold for monitoring may not have permitted the licensee to effectively monitor the functional condition of the system. As noted in the sequence of events, numerous condition reports and maintenance work orders had been written for the system, but none had reached the threshold established by the maintenance rule for increased monitoring. As a result, the overall system degradation continued to the point the automatic steam seal function had been isolated.

.3 Assess operating procedures and operator training concerning this scenario and determine if the procedures and training were adequate for operators to compensate for the lack of the automatic sealing steam control function (Objective 4)

a. Inspection Scope

The inspectors reviewed operating procedures, simulator training programs, Beginning-of-Shift Training, Night Orders, and Operating Orders to determine if the procedures and training were adequate for operators to compensate for the lack of the automatic sealing steam function.

b. Findings and Observations

Although there were several mechanisms which could have been used to provide guidance to operators, the inspectors did not find sufficient training was provided for the operators to compensate for the lack of automatic sealing steam function.

The status of the automatic sealing steam function was tracked via the Unit Supervisor and Control Board Operator turnover sheets on a daily basis. Although the summary section of two condition reports had stated operations personnel were aware of the potential for a loss of condenser vacuum upon a turbine trip, there was no formal guidance given to operators for actions for manually lowering condenser vacuum. Also, the licensee did not revise 34AR-650-125-2, STEAM SEAL PRESS LOW alarm response procedure, to provide guidance for the board operators to control sealing steam pressure in manual in accordance with the caution tag guidance and the system operating procedure. The licensee did, however, send a procedural change notice to the operations staff when the licensee procedure 34SO-N33-001-2, Seal Steam System,

had been changed to provide guidance for manual sealing steam pressure control, but there was no tracking or verification of who read the changes.

This lack of training and guidance became evident when, during the event, the operators chose to restore the automatic sealing steam system as guided by the alarm response procedure rather than follow the guidance on the caution tags to manually restore condenser vacuum. Although these actions successfully restored condenser vacuum, previous maintenance and operational history showed it was more fortuitous, rather than expected, that the automatic sealing steam system functioned normally. Had the automatic sealing steam system failed, the operators would have had to recognize the failure, remove the automatic steam seal system from operation and begin controlling the steam seal system in manual, all before condenser vacuum lowered sufficiently to isolate the bypass valves and lose the condenser heat sink. This was not a violation of regulatory requirements because the licensee had not specifically committed to controlling the system in manual.

Additionally, the Maintenance Rule Scoping Manual clearly stated that, although not risk-significant, the loss of sealing steam may require plant shutdown or may cause a plant trip on low condenser vacuum and can result in a loss of feedwater.

.4 Review post-scram cooldown data and determine if operator actions to control cooldown response was within procedural guidance (Objective 5)

a. Inspection Scope

The inspectors reviewed operator logs, the scram/transient analysis, computer data traces, procedures and cooldown data to determine if operators took the proper actions to control plant cooldown.

b. Findings and Observations

Based on the review, the operators controlled the cooldown in accordance with licensee procedures. However, the operator response was slowed by the decrease in condenser vacuum and trip of the only RFP.

When the reactor scrammed, the recirculation pumps tripped by design, and temperatures in the vessel increased because of a lack of forced circulation. Licensee procedure 34AB-C71-001-2, Scram Procedure, cautions operators the bottom head temperature will decrease rapidly with no forced circulation, and further states if forced circulation cannot be re-established within 30 minutes, an aggressive cooldown may have to be initiated, limited to less than 100EF cooldown rate in any one hour. Approximately 30 minutes after the scram, operators were able to restore water level and lower pressure to allow feeding with a condensate booster pump. Ten minutes later, operators started the 2A recirculation pump, and the water temperature in the bottom of the reactor vessel decreased approximately 129EF. However, the metal temperature on the bottom of the reactor only decreased approximately 39EF. Because of the complications with the loss of all normal feedwater, the operator was delayed

approximately 40 minutes after the scram to restart a recirculation pump. Once the recirculation pump was restarted, cooldown was controlled to less than 100EF per hour.

The Hatch technical specifications require cooldown be controlled to less than 100EF in one hour. If the cooldown rate exceeds this value, the cooldown must be evaluated. In September 1992, the licensee completed an analysis using General Electric information that determined a maximum water cooldown rate of 165EF in one hour still would not violate pressure and temperature limits, maximum stress on the lower head, and fatigue impact. As a result, the licensee determined the cooldown did not have any adverse consequences on the reactor pressure vessel.

.5 Review this event for generic safety implications

a. Inspection Scope

The inspectors evaluated if there could be industry-wide generic implications concerning the loss of normal feedwater following a turbine trip.

b. Observations

Although the Steam Seal system is considered a non-risk significant and non-safety related system, the loss of the automatic function of the system created difficulties for the operators during the event. Additionally, this was compounded by the fact the status and operational guidance of the automatic portion of the system was tenuous at best.

Given the circumstances surrounding the event, generic consideration could be given to reinforce the importance of mitigation equipment not normally emphasized during risk considerations for equipment outages. Although the manual control was available to the operators, guidance and training were not sufficient to provide a timely operator response to restore sealing steam.

4OA6 Meetings

On April 12, 2006, the inspectors presented the inspection results to Mr. Dennis Madison, and other members of his staff who acknowledged the observations. Additional exits were conducted on April 21 and 27, 2006, with Mr. Steve Douglas and Mr. Dennis Madison, respectively, and other members of their staff to present the results of additional information reviews. The inspectors confirmed that proprietary information was not provided or examined during the inspection.

Attachments: 1. Supplemental Information
2. Sequence of Events

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee personnel
M. Ajluni, Assistant General Manager - Plant Support
J. Dixon, Health Physics Manager
S. Douglas, Assistant General Manager - Plant Operations
M. Googe, Maintenance Manager
J. Hammonds, Operations Manager
J. Lewis, Training and Emergency Preparedness Manager
D. Madison, General Manager - Nuclear Plant
R. Varnadore, Engineering Manager

NRC
R. Bernhard, Senior Risk Analyst
C. Casto, Director, Division of Reactor Projects Region II
J. Hickey, Resident Inspector
J. Shea, Deputy Director, Division of Reactor Projects Region II

Attachment

LIST OF DOCUMENTS REVIEWED

Procedures

DI-OPS-61-1196, Control and Tracking of Operator Work-arounds
NMP-GM-002-GL03, Root Cause Determination Guideline
NMP-OS-003, Operational Decision Making Issue Evaluation Process
10AC-MGR-027-0, Applicability Determination
30AC-OPS-003-0, Plant Operations
31GO-OPS-007-0, Shift Logs and Relief of Personnel
31GO-OPS-010-0, Scram/Transient Analysis
31GO-OPS-014-0, Annunciator and Plant Component Control
34AB-C71-001-2, Scram Procedure
34AR-650-319-2, RFP Loop Seal LVL Low
34GO-OPS-001-2, Plant Startup
34GO-OPS-013-2, Normal Plant Shutdown
34SO-B31-001-2, Reactor Recirculation System
34SO-N21-007-2, Condensate and Feedwater System
34SO-N33-001-2, Seal Steam System
34SV-C71-005-2, Turbine Control Valve Fast Closure Instrument Functional Test
57CP-CAL-010-2N, Esterline Angus Megavar & KV Recorder
57CP-CAL-014-2, Pneumatic Controllers and Transmitters
90AC-OAM-001-0, Test and Surveillance Control

Miscellaneous Documents

2-CA-05-N33-00046, Steam Seal Unloader Bypass MOV Tagout
2-CA-05-N33-00076, Steam Seal Supply Controller Tagout
System Health Report for 2N33, Steam Seal System
HL-21046, Unit 2 Turbine Building Steam Seal System P&ID

Condition Reports:

2004109391, 2004109489, 2004109681, 2005101158, 2005101302, 2005101844, 2005105104, 2005105531, 2005105587, 2005105785, 2005105918, 2005106997, 2005111249, 2005111553, 2006104145, 2006104147, 2006104149, 2006104151, 2006104155, 2006104169, 2006104192, 2006104193, 2006104225, 2006104238, 2006104247, 2006104256,

Work Orders:

2041019301, 2041390001, 2041390701, 2041390703, 2042332301, 2042338101, 2042378501, 2042825001, 2050495101, 2050671301, 2050673802, 2051173201, 2051254601, 2051254603, 2051254701, 2051280901, 2051280902, 2051405601, 2051673901, 2052264001, 2052804701, 2053007501, 2053007502

Sequence of Events for Hatch Actions with the Automatic Seal Steam System

09/24/2004	CR 2004109391	2N33R301 thought not to be operating properly - actually found 2N33F001 not operating properly - MWO 2042332301
09/27/2004	CR 2004109489	2N33F001 not operating properly - replaced vertical and horizontal relay - MWO 2042338101
02/04/2005	CR 2005101158	Low steam seal pressure (1.6#), could not operate 2N33F004
02/04/2005	CR 2005101302	2N33R301 controller would not maintain seal steam pressure. Shift Manager stated - "Had U-2 scrammed prior to the shutdown, steam seals would have been lost and the ability to maintain condenser vacuum would have been difficult." - MWO 2041019301
02/05-3/14/2005		Unit 2 18th refueling outage
02/15/2005	CR 2005101844	R301 controller replaced 02/17/2005 - MWO 2050495101
05/09/2005	CR 2005105104	Indication S2N33F004 is leaking - MWO generated to inspect and repair - MWO 2051173201
05/22/2005	CR 2005105531	Received a steam seal low pressure alarm (1.8#). 2N33F001 is about 25% open (when it should be closed). Unit Supervisor stated, "However when the shift is required to lower RTP below 90% and a point is reached when greater than 1.5# seal pressure can't be maintained @ greater than 30% RTP the only option per the ARP is to enter the SCRAM procedure 34AB-C71-001-2." Generated forced outage MWO's 2051254601 & 2051254701 for F005 and F006 repair.
05/23/2005		Unit 2 forced outage begins (high chlorides in the main condenser)
05/24/2005	CR 2005105587	Concern calibrations on 2N33R301 should have been made when used to close 2N33F001 (actually not required). Generated MWO 2051280901
05/29/2005		Unit 2 forced outage ends
06/03/2005	CR 2005105918	2N33F001 remained approximately 20% open, when it should have been closed. 2N33R301 is controlling– the problem is in the F001 valve - MWO 2041390701 MWO 2041390703, MWO 2051280902,
06/06/2005	Operator logs	Using R301, I&C finally closed F001 after it was left 20% open after startup - MWO 2051405601
07/12/2005	CR 2005106997	F001 has drifted back open 10% - MWO 2051673901
07/14/2005	Operator logs	F001 adjusted with the AOV positioner
07/15/2005	Operator logs	F001 adjusted
07/15/2005	Operator logs	Caution tag 2-CA-05-2N33-00046 applied to F005: "2N33-F005 is leaking by it's closed seat, causing the 2N33-F001 Stm Seal Feed valve, to throttle open to assist in controlling stm seal header pressure in acceptable range," and R301: "Engineering does not recommend using 2N33-R301 (2N33-F001 Pressure controller) to close the 2N33-F001 as it is performing it's function to maintain steam seal header pressure. Refer to CAUTION for additional inf."
11/20/2005	CR 2005111249	Steam seal pressure is oscillating– R301 calibration is fine, F001 is leaking. Took manual control of the system by closing the F003 valve to isolate the automatic control function. Placed caution tag 2-CA-05-2N33-00073 on F003 "Throttle Steam Seal Supply Valve to Control Steam Seal Pressure" - MWO 2050671301, MWO 2052804701

12/02/2005	CR 2005111553	Attempted to restore the automatic seal steam system– unable to do so because of F001 - MWO 2053007501
12/24/2005	Operator logs	Caution tag 2–CA-05-2N33-00076: “Throttle valve as require to regulate seal steam header pressure per section 7.3.3. (Alternate seal steam pressure control) of 34SO-N33-001-2 .” This was hung on F004.
02/18/2006	Operator logs	Steam seal pressure readjusted in manual per procedure.
04/05/2006	Operator logs	Unit 2 turbine and reactor trip - recirculation pumps trip, 8 of 11 SRV’s open, and water level climbs rapidly. Both RFPs trip on high water level as designed. Water level begins to decrease. When water level is in the normal band, the 2A RFP is started, but vacuum lowers sufficiently for the RFP to trip (18" Hg), securing all sources of normal feedwater. Operators restored vacuum by placing the automatic steam seal system in operation, rather than throttling open the manual valve, as per the caution tag. Once vacuum is restored, the operator starts the 2A RFP, then RCIC and HPCI to restore water level, then secures HPCI, followed by RCIC.
04/06/2006	CR 2006104238	Automatic sealing steam still not being controlled effectively.
04/07/2006	CR 2006104247	Controller R301 has too high of a range to effectively control automatic seal steam pressure