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

January 26, 2004

NOED 03-2-007

Florida Power and Light Company
ATTN: Mr. J. A. Stall, Senior Vice President
Nuclear and Chief Nuclear Officer
P. O. Box 14000
Juno Beach, FL 33408-0420

SUBJECT: ST. LUCIE NUCLEAR PLANT - NRC INTEGRATED INSPECTION REPORT 05000335/20003007 AND 05000389/2003007

Dear Mr. Stall:

On December 27, 2003, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your St. Lucie Units 1 and 2. The enclosed integrated inspection report documents the inspection findings which were discussed on January 5, 2004, with Mr. Jefferson 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.

Based on the results of this inspection, the inspectors identified one finding of very low safety significance (Green). This finding was determined to involve a violation of NRC requirements. However, because of the very low safety significance and because it was entered into your corrective action program, the NRC is treating this violation as a non-cited violation (NCV), in accordance with Section VI.A of the NRC's Enforcement Policy. If you contest this NCV, you should provide a response, within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory 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 Regulatory Commission, Washington, DC 20555-0001; and the NRC Senior Resident Inspector at the St. Lucie facility.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosure 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 Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Joel T. Munday, Chief
Reactor Projects Branch 3
Division of Reactor Projects

Docket Nos.: 50-335, 50-389
License Nos.: DPR-67, NPF-16

Enclosure: Inspection Report 05000335/2003007
and 05000389/2003007
w/Attachment - Supplemental Information

cc w/encl: (See page 3)

cc w/encl:

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U.S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket Nos.:	50-335, 50-389
License Nos.:	DPR-67, NPF-16
Report Nos.:	05000335/2003007, 05000389/2003007
Licensee:	Florida Power & Light Company (FPL)
Facility:	St. Lucie Nuclear Plant, Units 1 & 2
Location:	6351 South Ocean Drive Jensen Beach, FL 34957
Dates:	September 28 - December 27, 2003
Inspectors:	T. Ross, Senior Resident Inspector R. Aiello, Senior Licensed Examiner (Section 1R11.1) S. Sanchez, Resident Inspector S. Ninh, Senior Project Engineer (Section 4OA1.1) K. Green-Bates, Resident Inspector Turkey Point (Section 1R6)
Approved by:	Joel Munday, Chief Reactor Projects Branch 3 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000335/2003007, 05000389/2003007; 09/28/2003 - 12/27/2003; St. Lucie Nuclear Plant, Units 1 & 2; Problem Identification and Resolution.

The report covered a three month period of inspection by resident inspectors, a senior project engineer, and a senior license examiner from Region II. One Green non-cited violation (NCV) was identified. The significance of most findings is identified by their color (Green, White, Yellow, Red) using IMC 0609, “Significance Determination Process” (SDP). Findings for which the SDP does not apply may be Green or be assigned a severity level after NRC 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 Finding

Cornerstone: Barriers

Green. The inspector identified a non-cited violation of Technical Specification 3.6.2.2.a. for failure to maintain the Unit 1 spray additive tank NaOH concentration within the prescribed range of 28.5 to 30.5%.

This finding is greater than minor because if left uncorrected it could have resulted in a condition where an insufficient amount of NaOH existed to adequately buffer the pH of reactor coolant inside containment during design basis accidents. The finding affected the Barriers Cornerstone, and was determined to be of very low safety significance according to the SDP Phase 1 worksheet since it did not represent a degradation in the radiological barrier function of the containment.

B. Licensee-Identified Violations

None

Report Details

Summary of Plant Status

Unit 1 operated at essentially full power for the entire period. Unit 2 operated at essentially full power until December 4, when it was manually tripped from 60% power due to a motor bearing failure on the 2A condensate pump. The unit was returned to 100% power on December 7. On December 20, Unit 2 automatically tripped from full power when the main generator experienced a total loss of excitation. The unit was returned to full power on December 25, but shortly thereafter it experienced another main generator excitation anomaly and the unit was manually brought offline on December 26. After replacing several modules in the excitation control circuitry, the unit was restarted on December 28 and reached full power on December 29.

1. REACTOR SAFETY
Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity

1R01 Adverse Weather Protection

a. Inspection Scope

During the week of December 14, the inspectors verified the status of licensee actions in response to the predicted onset of cold weather. This verification included physical walkdowns of selected critical safety systems for both units and discussions with responsible licensee personnel regarding systems, structures, and components (SSCs) vulnerable to cold weather. The inspectors also reviewed the status of procedure ADM-04.03, Cold Weather Preparations, and specifically examined the following areas:

- Unit 1 instrumentation and sensing lines for the Refuel Water Tank (RWT), Condensate Storage Tank (CST), Auxiliary Feedwater (AFW), and Main Feedwater Systems
- Unit 2 instrumentation and sensing lines for the RWT, CST, AFW, and Main Feedwater Systems.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment

a. Inspection Scope

Partial Equipment Walkdowns

The inspectors conducted three partial alignment verifications of the safety-related systems listed below to review the operability of required redundant trains or backup systems while the other trains were inoperable or out of service (OOS). These inspections included reviews of applicable Technical Specifications (TS), plant lineup procedures, operating procedures, and/or piping and instrumentation drawings which were compared with observed equipment configurations to identify any discrepancies that could affect operability of the redundant train or backup system.

- 2A Emergency Diesel Generator (EDG) per OP-2-2200020, EDG Standby Lineup, while 2B EDG was OOS for surveillance testing
- 1A AFW per 1-NOP-09.11, AFW System Initial Alignment, while 1C AFW was OOS for maintenance
- Unit 2 Charging System per 2-NOP-02.11, Charging and Letdown Initial Alignment, after maintenance performed

b. Findings

No findings of significance were identified.

.2 Complete Equipment Walkdown

a. Inspection Scope

During the week of October 26, the inspectors completed a detailed equipment alignment verification of the Unit 2 Intake Cooling Water (ICW) System using licensee operating procedure OP-2-0640020, ICW System Operation, and plant drawing 2998-G-082, Sheet 2. The inspectors also reviewed applicable sections of the Updated Final Safety Analysis Report (UFSAR) and TS. Furthermore, the inspectors interviewed the responsible system engineer regarding all outstanding work requests and orders, recent applicable Condition Reports (CRs), and any outstanding Temporary System Alterations (TSA) or Plant Management Action Items (PMAIs) that could affect system alignment and operability. The inspectors specifically examined the following aspects: valves were correctly positioned and did not exhibit excessive leakage; electrical power was available as required; major system components were correctly labeled, lubricated, cooled, and ventilated; essential support systems were operational; and valves were locked as required.

b. Findings

No findings of significance were identified.

1R05 Fire Protection

Routine Inspections

a. Inspection Scope

The inspectors conducted tours of the following fourteen fire areas and/or witnessed associated activities listed below during the inspection period to verify that they conformed with Administrative Procedure AP-1800022, Fire Protection Plan. The inspectors specifically examined any transient combustibles in the areas and any ongoing hot work or other potential ignition sources. The inspectors also assessed whether the material condition, operational status, and operational lineup of fire protection systems, equipment and features were in accordance with the Fire Protection Plan. Furthermore, the inspectors evaluated the use of any compensatory measures being performed in accordance with the licensee's procedures and Fire Protection Plan.

- Unit 2 Cable Spreading Room (CSR)
- Unit 1 Non-Qualified Fire Stops In CSR and Reactor Auxiliary Building (RAB)
- Units 1 and 2 Steam Trestle Areas
- Unit 1 Fuel Handling Building
- Unit 2 Emergency Core Cooling System (ECCS) Pumps Area
- Unit 2 AFW Pumps Area
- Unit 1 ECCS Pumps Area
- Unit 2 Charging Pumps Area
- Unit 1 Main Control Room
- Unit 1 Component Cooling Water (CCW) Area
- Unit 1 Transformer Area
- Unit 2 Transformer Area
- Unit 1 ICW Area
- Unit 2 ICW Area

b. Findings

No findings of significance were identified.

1R6 Flood Protection

a. Inspection Scope

The inspectors reviewed St. Lucie Unit 2 UFSAR Sections 3.2 and 3.4, as well as adverse weather procedures and other flood mitigation documents which depicted design flood levels and protection for areas and structures containing risk and safety-related equipment, to determine consistency with design requirements and identify areas that may be affected by external flooding.

A general site walkdown was conducted, with a specific walkdown of the risk significant RAB to ensure that external flood protection measures were in accordance with design specifications. Specific attributes that were checked included structural integrity of exterior walls, wave runup protection stoplogs at south and east walls, roof and roof drains and potential interconnections between roof drain piping and interior floor slab drainage systems. Structures and equipment used for flood mitigation, were reviewed for operability and/or structural integrity during a design basis instantaneous rain event. Potential flooding sources were examined to verify proper maintenance.

A review of outstanding maintenance work orders and related condition reports was performed to verify that deficiencies did not significantly affect the RAB external flood mitigating functions.

The inspectors also reviewed St Lucie Unit 2 UFSAR Sections 3.6.1.2.2 and Appendix 3.6F, as well as procedures and other flood mitigation documents which depicted design flood levels and protection for areas containing risk and safety-related equipment, to determine consistency with design requirements and identify areas that may be affected by internal flooding outside containment.

A general site walkdown was conducted, with a specific walkdown of the risk significant Unit 2B Safeguards room to ensure that internal flood protection measures were in accordance with design specifications. Specific attributes that were checked included structural integrity, flood platform heights for safety equipment, the sealing of the switchgear room penetrations, and unobstructed floor drains. Equipment used for flood mitigation, were reviewed for operability and/or structural integrity. Potential flooding sources were examined to verify proper maintenance.

A review of outstanding maintenance work orders and related condition reports was performed to verify that deficiencies did not significantly affect the Unit 2 Safeguard rooms internal flood mitigating functions. The inspectors discussed with engineering and maintenance management equipment issues to verify that identified problems were being appropriately resolved in a timely fashion.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification

.1 Annual Operating Test Results

a. Inspection Scope

On October 31, 2003, the licensee completed the requalification annual operating tests, required to be given to all licensed operators by 10 CFR 55.59(a)(2). The inspectors reviewed the overall pass/fail results of the individual operating tests, and the crew simulator operating tests. These 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.

.2 Routine Licensed Operator Requalification Program Inspection

a. Inspection Scope

On November 19, 2003, the inspectors observed and assessed licensed operator performance during a simulator evaluation involving two different scenarios. During this simulator evaluation the operating crew responded to several different failures of critical equipment (e.g., stuck out control element assemblies, stuck open relief valve), followed by a station blackout event, and then in a different scenario a loss of coolant accident. The inspectors specifically evaluated the following attributes related to the operating crew's performance:

- clarity and formality of communication
- ability to take timely action to safely control the unit
- prioritization, interpretation, and verification of alarms
- correct use and implementation of applicable Emergency Operating Procedures (EOP), such as EOP-03 and EOP-10
- timely and appropriate Emergency Action Level declarations
- oversight and direction provided by Operations supervision
- effectiveness of the post training critique

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessments and Emergent Work Control

a. Inspection Scope

The inspectors reviewed the risk assessments for the following SSCs that were OOS for planned emergent work. The inspectors also walked down and/or reviewed the scope of work to evaluate the effectiveness of licensee scheduling, configuration control, and management of online risk in accordance with 10 CFR 50.65(a)(4) and applicable program procedures such as ADM 17.16, Implementation of the Configuration Risk Management Program. Furthermore, the inspectors interviewed responsible Senior Reactor Operators on-shift, verified actual system configurations, and specifically evaluated results from the online risk monitor (OLRM) for the combinations of OOS risk significant SSCs listed below.

- 2A AFW pump, 2A EDG, and 2C ICW pump OOS, with valves HCV 14-8B/10 closed
- 2B EDG and 2C ICW pump OOS, with valves HCV 14-8B/10 closed
- 1B Containment Instrument Air (IA), 1C Charging pump, and 1C AFW pump OOS
- Station Blackout (SBO) Cross-tie, 1AB 4KV Bus, 1C CCW pump, 1C ICW pump, and 1B Containment IA OOS
- 2C AFW pump, 2B CCW Heat Exchanger, 2B Boric Acid Makeup (BAM) tank OOS
- Multiple 4K Breakers failure to close
- 1A EDG, 2B BAM tank, 2A Charging pump, and 2C AFW pump OOS

b. Findings

No findings of significance were identified.

1R14 Personnel Performance During Nonroutine Plant Evolutions and Events

a. Inspection Scope

For the non-routine evolutions and events described below, the inspectors evaluated operator performance by interviews, observations and reviewing available information (e.g.,operator logs, plant computer data, and strip charts) to determine what occurred and how the operators responded, and to verify that the response was in accordance with plant procedures (e.g., normal and abnormal operating procedures, EOPs, etc.):

- On December 4, 2003, Unit 2 was manually tripped due to loss of the 2A condensate pump (motor bearing failure). The inspectors observed the subsequent reactor startup and power ascension by Operations in accordance with procedure 2-GOP-302, Reactor Plant Startup - Mode 3 to Mode 2. During the later stages of the power ascension, the inspectors witnessed performance of the manual calorimetric per procedure OP-2-3200020 and the nuclear power and ΔT power calibration per procedure 2-OSP-69.01.

- On December 20, 2003, Unit 2 automatically tripped due to a loss of main generator excitation. Following the event, the inspectors responded to the control room to observe operators' performance of EOP-1, Standard Post Trip Actions, subsequent entry into EOP-2, Reactor Trip Recovery, and reviewed sequence of events recorder output. The inspectors also observed Unit 2 reactor startup and approach to criticality by Operations in accordance with procedure 2-GOP-302, Reactor Plant Startup - Mode 3 to Mode 2.

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications

a. Inspection Scope

The inspectors reviewed the modification package for Plant Change and Modification (PC/M) 03134 to replace the existing Unit 2 charging pump fluid cylinders. As part of the PC/M, the inspectors reviewed the 10 CFR 50.59 screening; safety classification determination; seismic; materials; design pressure, temperature, and flow evaluations; and Appendix R review performed by the licensee. The inspectors also verified that TS changes and NRC approval were not required for this modification. Furthermore, the inspectors observed portions of the 2A and 2C charging pump fluid cylinder replacements. The inspectors conducted walk downs and monitored operation of the modified pumps to verify proper installation and assure the impact on TS required and safety-related equipment was adequately addressed.

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing

a. Inspection Scope

The inspectors witnessed and reviewed six post maintenance test (PMT) activities of the risk significant SSCs listed below. The following aspects were specifically inspected: (1) Effect of testing on the plant recognized and addressed by control room and/or engineering personnel; (2) Testing consistent with maintenance performed; (3) Acceptance criteria demonstrated operational readiness consistent with design and licensing basis documents such as TS, UFSAR, and others; (4) Range, accuracy and calibration of test equipment; (5) Step by step compliance with test procedures, and applicable prerequisites satisfied; (6) Control of installed jumpers or lifted leads; (7) Removal of test equipment; and, (8) Restoration of SSCs to operable status. The inspectors also reviewed problems associated with the PMTs to ensure that they were correctly identified and appropriately entered into the corrective action program.

- 1A EDG run and load test per 1-EMP-59.06 following governor limit switch replacement
- Ultimate heat sink valve stroke test per OP-0360050 following planned maintenance
- Unit 2 fuel cask crane load test per CRN 02086-11125 following initial installation
- Unit 1 SBO Cross-tie Beaker and 1AB Bus testing per 0-EMP-52.05 following planned maintenance
- 2A Charging pump test per P/CM 03134 and OP 2-0010125A following fluid cylinder replacement
- 1A EDG start and load test per OP-1-12200050A following repairs

b. Findings

No findings of significance were identified.

1R20 Refueling and Other Outage Activities

.1 Unit 2 Short Notice Outages Following Two Reactor Trips

a. Inspection Scope

Following each of the Unit 2 reactor trips on December 4, and 20, 2003, the licensee entered into a short notice outage (SNO). In the first instance, the SNO only lasted a day, in the second instance it lasted about eight days. During these SNOs, the inspectors observed shutdown activities and monitored unit status to verify compliance with applicable Mode 3 TS and operating procedures. The inspectors also attended status and planning meetings in the Outage Control Center, and reviewed plant restart schedules. The inspectors observed licensee processes for controlling SNO-related work activities in accordance with their administrative procedures. The inspectors also reviewed applicable CRs, attended Facility Review Group (FRG) meetings prior to restart regarding the post-trip review and resolution of post-trip equipment problems. In particular, during the second SNO, the inspectors focused their efforts on reviewing the licensee's resolution of the multiple equipment problems identified during the reactor trip of December 20. Lastly, the inspectors monitored portions of the Unit 2 startup on December 5, along with the subsequent power ascension, in accordance with applicable TS and operating procedures. Likewise, between December 23 and 28, the inspectors monitored portions of the reactor startups and subsequent power ascensions, conducted by the licensee following the December 20 reactor trip. Furthermore, licensee identification and resolution of problems that occurred during the SNO were also examined by the inspectors.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing

a. Inspection Scope

The inspectors witnessed all or portions of the following four surveillance tests and monitored test personnel conduct and equipment performance, to verify that testing was being accomplished in accordance with applicable operating procedures (OP), and operations surveillance procedures (OSP). The actual test data was reviewed to verify it met TS, UFSAR, and/or licensee procedure requirements. The inspectors also verified that the testing effectively demonstrated the systems were operationally ready, capable of performing their intended safety functions, and that identified problems were entered into the corrective action program for resolution.

- OP-1-0010125A, Surveillance Data Sheets for 1A Charging Pump Quarterly Code Run (Inservice Testing)
- OP-1-2200050A, 1A EDG Periodic Test and General Operating Instruction
- OP-2-0400053, Engineered Safeguards Relay Test
- 1-OSP-66.01, Control Element Assembly Quarterly Exercise

b. Findings

No findings of significance were identified.

1REP Equipment Availability, Reliability and Functional Capability - Pilot

a. Inspection Scope

The inspectors reviewed the reliability problems associated with the SSCs listed below, including associated condition reports. The inspectors verified the licensee's maintenance efforts met the requirements of 10 CFR 50.65 and Administrative Procedure ADM-17.08, Implementation of 10 CFR 50.65, The Maintenance Rule. The inspectors' efforts focused on the licensee's work practices and ability to identify and address common causes, maintenance rule scoping, characterization of reliability issues and assigning unavailability time, determination of a(1) and a(2) classification, corrective actions, and the appropriateness of established performance goals and monitoring criteria. The inspectors also attended applicable expert panel meetings, interviewed responsible engineers, and observed some of the corrective maintenance activities. Furthermore, the inspectors verified that equipment problems were being identified at the appropriate level and entered into the corrective action program.

- CR 03-3374, 1A Charging Pump Excessive Secondary Packing Leakage
- CR 03-3433, Failure of Unit 2 Level Control Valve LCV-9005 and Main Feedwater Regulating Valve
- CR 03-2751, Unit 2 125 Volt Direct Current Battery Charger Repetitive Maintenance Preventable Functional Failure
- CR 03-2670, Unit 1 Electrical Equipment Room Fan HVS-5A Exceeded Unavailability Hours

The inspectors reviewed the operability evaluations for the following three interim and/or final CR dispositions to ensure that TS operability was properly supported and the affected SSC remained available to perform its safety function with no unrecognized increase in risk. As applicable, the inspectors reviewed the UFSAR, and associated supporting documents and procedures, and interviewed plant personnel to assess the adequacy of the interim CR disposition.

- CR 03-3470, 1A EDG Output Breaker Opened Prematurely During EDG Shutdown After Surveillance Run
- CR 03-3901, 1A1 EDG Governor Fuel Rack Went to Unexpected Position During EDG Shutdown After Surveillance Run
- CR 03-4553, Potential Operability Impact on 1C AFW Pump From Problems Associated With 2C AFW Pump

The inspectors routinely reviewed the Operator Work Around (OWA) log for both units and discussed new items with Operations supervision. In particular, the inspectors examined the OWA associated with the Unit 1 Quench Tank Pressure Control according to OPS-510. The inspectors also routinely walked down unit main control boards (MCB), reviewed operator chronological logs and equipment OOS logs, and examined MCB plant work order (PWO) tags for potential OWAs. Furthermore, the inspectors verified OWAs were being identified and properly entered into the corrective action program.

The inspectors performed a semi-annual evaluation of the potential cumulative effects of all outstanding Unit 1 and 2 OWAs. The inspectors evaluated all outstanding OWAs for their cumulative effects, and discussed these potential effects with control room supervision and operators. The inspectors also reviewed the minutes for the third quarter OWA Team meeting of 2003, which met to systematically examine individual and cumulative OWA status and repair priority, and assess overall risk.

The inspectors reviewed the following Temporary System Alterations (TSAs). The technical evaluations and associated 10CFR50.59 screening of these TSAs were reviewed against the system design bases documentation to ensure that - (1) the modifications did not adversely affect operability or availability of other systems, (2) the installation was consistent with applicable modification documents, and (3) did not affect TS or warrant prior NRC approval. The inspectors also walked down the installation of the TSAs to verify configuration control was maintained. Furthermore, the inspectors verified and reviewed required condition monitoring by Operations, and discussed compensatory actions detailed by the TSAs with Operations supervision.

- TSA 2-03-014, Unit 2 Reverse Alarm Logic for Instrumentation PIA-1140 Reactor Coolant Gas Vent System Monitor
- TSA 2-03-010, Unit 2 Nuclear Instrumentation High Rate of Change of Power Trip Bypassed

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator (PI) Verification

.1 Initiating Events Cornerstone

a. Inspection Scope

The inspectors assessed the accuracy of the following Performance Indicators (PIs) reported to the NRC in accordance with the criteria specified in NEI 99-02, Regulatory Assessment Performance Indicator Guideline, and ADM-25.02, NRC Performance Indicators. The inspectors reviewed the PI data of both Units 1 and 2 for the previous four quarters (i.e., Fourth Quarter 2002 through Third Quarter 2003). Monthly Operating Reports, Maintenance Rule history, and Licensee Events Reports were reviewed to verify the reported PI data was complete and accurate.

- Unplanned Scrams per 7000 Critical Hours (Unit 1)
- Unplanned Scrams per 7000 Critical Hours (Unit 2)
- Unplanned Scrams With Loss of Normal Heat Removal (Unit 1)
- Unplanned Scrams With Loss of Normal Heat Removal (Unit 2)
- Unplanned Transients per 7000 Critical Hours (Unit 1)
- Unplanned Transients per 7000 Critical Hours (Unit 2)

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems

.1 Routine Review Of Condition Reports

a. Inspection Scope

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 all condition reports as they were entered into the licensee's corrective action program.

b. Findings and Observations

There were no specific findings identified from this overall review of the CRs issued each day, except as discussed below.

.2 Annual Sample Review - Unit 1 Sodium Hydroxide Tank

a. Inspection Scope

During the routine screening of CRs mentioned above, the inspectors selected CR 03-3305 for further inspection. This CR was initiated to address the lack of administrative controls over the Unit 1 sodium hydroxide (NaOH) tank concentration and replenishment chemicals.

The inspectors promptly met with Chemistry supervision to discuss in greater detail the circumstances surrounding CR 03-3305, including the inspectors' concerns regarding TS operability. Following this meeting, the inspectors met with the Plant General Manager (PGM) to discuss Chemistry department's approach to resolving CR 03-3305 and the need for timely action. The inspector also reviewed CR 03-3305 when it was completed, along with several other CRs that were generated as a consequence of this issue (CR 03-3357, 3422, and 4221). Furthermore, the inspectors reviewed the associated Licensee Event Report 50-389/2003004, and interviewed the acting Chemistry Department Head.

b. Findings and Observations

Introduction. A Green non-cited violation (NCV) was identified by the NRC for the licensee's failure to maintain the Unit 1 NaOH spray additive tank concentration within the limits prescribed by TS 3.6.2.2.a.

Description. On or about September 10, 2003, the semi-annual surveillance test required by TS 4.6.2.2.b. to measure the Unit 1 spray additive tank NaOH concentration came due. In preparations for this test, Chemistry supervision became aware that the previous test results over the past year indicated that the NaOH concentration was right at the lower TS limit of 28.5% by weight. Recognizing that a chemical addition to the tank would be necessary, attempts were made to locate additional concentrated NaOH. But when none could be found, CR 03-3305 was initiated on September 16 and the surveillance test remained deferred. The inspectors subsequently questioned operability of the Unit 1 spray additive tank, and also the licensee's plans to add NaOH before sampling the tank since this would constitute "preconditioning" to ensure TS compliance and would not be representative of the as-found conditions. The inspectors' concerns was discussed with the licensee who agreed to sample the tank prior to adding chemicals.

On September 19, a sample of the Unit 1 spray additive tank was taken and the results indicated the tank concentration was 27.9%, which was well below the minimum TS limit of 28.5%. The licensee promptly entered the 72 hour TS 3.6.2.2 action statement, and initiated CR 03-3357. Shortly thereafter, chemicals were located and added to the tank to successfully restore the tank concentration within the allowed TS band.

Analysis. The licensee's investigation subsequently concluded that the apparent sudden drop in tank concentration was not due to any type of dilution event, but rather was the consequence of slow deterioration over a long period of time that went unrecognized due to inadequate mixing of the tank during prior surveillance tests. In early 1999, system operation of the spray additive tank was changed to secure the continuous nitrogen supply to the tank. This operational change effectively terminated the continuous nitrogen sparging which had kept the tank contents well mixed. However, the chemistry sampling procedures were not updated. An inadequate sampling procedure, combined with the chemists' failure to understand that the tank's nitrogen system was isolated, resulted in a stagnant tank condition for several years and contributed to an apparent stratification of the NaOH concentration in the tank. The licensee's failure to adequately mix the tank resulted in nonrepresentative samples of the tank during this period. Also, the lack of administrative controls to alert management that the tank was approaching and had apparently reached the limit over a year ago resulted in lost opportunities to recognize the condition earlier.

The requirements of TS 3.6.2.2. provides limits of both the concentration and volume of NaOH to ensure design basis accident conditions in containment are maintained within a certain pH band. The licensee conducted an operability evaluation of the reduced NaOH concentration, and concluded that a sufficient quantity of NaOH had existed in the tank at all times in order for it to perform its intended safety function. Although the NaOH concentration was less than the TS minimum, the excess volume of NaOH that was maintained above the minimum required by TS was enough to ensure the quantity of NaOH satisfied the assumptions used in the safety analyses for post-accident conditions in containment.

Failure to adequately monitor and maintain the Unit 1 spray additive tank NaOH concentration above the TS limit is a finding considered greater than minor because if left uncorrected it could have resulted in a condition of inadequate pH buffering during design basis accidents. Controlling the pH of reactor coolant inside containment is important during design basis accidents for mitigating iodine and to minimize potential effects of stress corrosion cracking on wetted surfaces. The finding was also determined to be under the barriers cornerstone and was of very low safety significance according to the SDP Phase 1 worksheet since it did not represent a degradation in the radiological barrier function of the containment.

Enforcement. A spray additive tank containing between 28.5% and 30.5% by weight NaOH solution is required by TS 3.6.2.2.a. Contrary to this requirement, the NaOH solution contained in the Unit 1 spray additive tank was below 28.5% for longer than allowed by the TS action statement. Although the precise point in time when the tank concentration dropped below the TS requirement could not be determined, this condition has reasonably existed for over one year. However, because this violation is of very low safety significance and was addressed by the licensee's corrective action program (i.e., CR 03-3305, 3357, 3422, and 4221), this violation is being treated as a noncited violation (NCV) consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000335/2003007-01, Failure To Maintain Spray Additive Tank NaOH Concentration Within TS Limits.

.3 Annual Sample Review - Employee Concerns and Corrective Action Program Effectiveness In Dealing With Safety Conscious Work Environment Issues

a. Inspection Scope

The inspectors searched the corrective action program (CAP) data base for the past two years and specifically reviewed all the anonymous CRs, and any CRs related to harassment and intimidation (H&I), discrimination, or safety conscious work environment (SCWE). The inspectors also interviewed the CAP supervisor, Performance Improvement Department Manager, Human Resources Manager, Site Vice President, Maintenance Manager, Speakout Supervisor, and Corporate Nuclear Review Board (CNRB) chairman regarding the effectiveness of the CAP and Employee Concerns program (i.e., Speakout) for dealing with H&I, Discrimination, and SCWE issues. In addition, the inspectors attended an CNRB meeting that addressed recent allegation referrals; a routine Quarterly all-hands meeting by the site Vice President; a site-wide training session about Davis Besse lessons learned and SCWE; and a training session "On Maintaining a SCWE" for supervisors by the corporate lawyer. Furthermore, the inspectors reviewed the self-assessment report and survey results related to an SCWE questionnaire that was distributed to all plant employees as part of an industry initiative regarding Davis Besse lessons learned. The inspectors also reviewed CR 03-2823 which addressed the Areas for Improvement and recommendations identified in the aforementioned self-assessment.

The inspectors reviewed Speakout (Employee Concerns Program) records for the period January 2001, through October 2003, to determine if - the investigations were of sufficient scope to adequately address the concern; any safety significant issues that were identified were addressed in a manner commensurate with safety; the extent of condition was adequately assessed; generic implications or previous occurrences were considered; the identity of the concerned individual was adequately protected; and the corrective actions, if any, were appropriately focused to address the concern and completed in a timely manner commensurate with safety. Selected samples from

Speakout files included all cases that were categorized as H&I, discrimination, or SCWE; selected samples also included allegations referred to the licensee from the NRC for calender years 2001 through October 2003. In addition, the inspector reviewed selected samples of licensee assessments and corrective action documents to determine if concerns identified in these programs had been adequately addressed using the aforementioned criteria.

b. Findings and Observations

No safety significant findings were identified. In general, the Speakout organization was effectively investigating and facilitating the resolution of employee concerns, including allegation referrals. There were only a few specific cases in which the inspectors identified that the Speakout investigation did not fully address all issues or the Speakout file was incomplete. In particular, Speakout cases NSS-PSL-02-024 and NSS-PSL-03-035 required supplemental investigations by Speakout to followup on ancillary issues that were discovered during the original investigation but had not been addressed. Also, several of the Speakout files lacked complete documentation regarding closure of Speakout recommendations and documented completion of associated corrective actions (e.g., NSS-PSL-03-001 and 026). The specific details of these deficiencies were discussed with Speakout personnel.

With regard to the corrective action program, there was a marked increase in anonymous CRs since the year 2000. During prior years, the number of anonymous CRs was less than 5 per year. However starting with the year 2001, the trend of anonymous CRs increased, markedly; by the year 2003 the number had reached over 30. Although many of these anonymous CRs were initially given a significance level of “trend only,” they were not actually trended until prompted by the NRC. Furthermore, many of these CRs included elements of H&I, discrimination, or lack of SCWE, that were not specifically addressed as part of the CR closeout. The inspectors concluded, that the licensee’s CAP did not adequately address CRs involving H&I, discrimination, and SCWE. In response to this conclusion, the licensee promptly revised their CAP procedure to require referring similar issues to Speakout for investigation.

In July 2003, the licensee conducted a comprehensive survey of plant employees related to SCWE, as part of an industry initiative regarding Davis Besse Lessons Learned. About 60% of the plant population participated in the survey. From the survey results the licensee discerned numerous insights and areas for improvement that were entered into the CAP primarily via CR 03-2823, and associated Plant Manager Action Items. However, as part of the survey, a large number of individuals provided additional comments on issues or problems that they believed were not being adequately resolved. These issues included program issues, process issues, and equipment problems. Although the survey assessment team acknowledged and provided a summary list of these comments in their report, they did not systematically address the comments or enter them into the CAP. The inspectors discussed this issue with licensee management, who promptly initiated a detailed review of all the comments to ensure any specific unaddressed problems were entered into the CAP. Furthermore, the inspectors determined that several key departments (i.e., Maintenance, Operations, and System Engineering) were under-represented in the plant population that participated in the survey. Licensee management was aware of this apparent anomaly and was pursuing efforts to ensure this lack of participation was not indicative of unidentified SCWE issues. The licensee indicated they were intending to conduct an another SCWE-related survey in the Spring.

4OA3 Event Follow-up

.1 (Closed) Licensee Event Report (LER) 05000335/2003-004-00, Operation of NaOH Tank Outside TS Limits

On October 16, 2003, the licensee completed their investigation into the past operability of the Unit 1 spray additive tank in light of an out-of-specification low NaOH concentration sample that was drawn on September 19, 2003. The licensee subsequently concluded that the Unit 1 spray additive tank had been inoperable in excess of the TS 3.6.2.2 allowed outage time and was thereby reportable in accordance with 10 CFR 50.73. The inspectors have reviewed this LER, and associated CRs, and determined that a violation of NRC requirements did occur. This violation and the inspectors' findings are addressed in Section 4OA2.2 of this report. The inspectors also reviewed, discussed with responsible Chemistry personnel and Supervision, and verified selected corrective actions identified in this LER, and CRs 03-3305, 3357, 3422, and 4221. This LER is closed.

.2 (Closed) LER 05000389/2003-002-00,Two Flaws Identified During Reactor Pressure Vessel Head Inspections

On April 30, 2003, the reactor pressure vessel head surface and associated penetration nozzles were inspected during the St. Lucie Unit 2 refueling outage. Although the head surface visual inspection revealed no evidence of reactor coolant system boundary leakage, ultrasonic testing identified an axial flaw in each nozzle for reactor pressure vessel head penetrations 18 and 72. Neither flaw extended through the nozzle wall and there was no identified reactor coolant system pressure boundary leakage associated with these penetrations. No other indications were identified during the inspection activities. The cause of the nozzle flaws was attributed to primary water stress corrosion cracking. The subject nozzles were replaced during the refueling outage. The LER was reviewed by the inspectors and no findings of significance were identified. The licensee documented this problem in CR 03-1538. No violations of NRC requirements were identified. This LER is closed.

.3 Unit 2 Manual Reactor Trip

a. Inspection Scope

On December 4, 2003, the Unit 2 reactor was manually tripped from 60% power due to a sudden failure of the motor bearing for the 2A condensate pump. The unit had been operating at 100% power when it was reported to the control room that the motor bearing for the 2A condensate pump was overheating. Operators promptly began a rapid downpower to remove the 2A condensate pump from service. However, when it became evident that failure was imminent, operators manually tripped the unit and entered their emergency operating procedures (EOP). An inspector promptly responded to the control room and verified the unit was stable in Mode 3, and confirmed that all safety-related mitigating systems had operated properly. The inspector observed operator and plant response and discussed the event with Operations personnel. Subsequently, inspectors also discussed the risk significance with Region II personnel and verified that appropriate notifications were made in accordance with 10 CFR 50.72. Furthermore, an inspector reviewed the post-trip report and interim disposition of CR 03-4327; and attended the Facility Review Group (FRG) meetings for Mode 2 restart.

b. Findings

No finding of significance were identified

.4 Unit 2 Automatic Reactor Trip

a. Inspection Scope

On December 20, 2003, Unit 2 experienced an automatic reactor trip from 100% power due to a loss of main generator excitation which caused a generator lockout and main turbine trip. The inspectors promptly responded to the control room and verified the unit was stable in Mode 3, and observed operator actions in accordance with applicable EOPs. The inspectors also examined safety equipment and mitigating system performance by reviewing plant parameters, strip charts, operator logs, and the Sequence of Events Recorder; and discussed the event with Operations personnel and members of the licensee's Event Review Team. The inspectors subsequently discussed the risk significance of this event with Region II personnel and verified that appropriate notifications were made in accordance with 10 CFR 50.72. Furthermore, the inspector reviewed the post-trip report and interim disposition of CR 03-4539; and attended several FRG meetings held to address the outstanding restart issues and authorize startup.

b. Findings

No findings of significance were identified. However, an unresolved item (URI) was identified regarding the unexpected overspeed trip of the 2C AFW turbine-driven pump. Shortly after the reactor trip, the 2C AFW pump had received a valid signal to start from the Auxiliary Feedwater Actuation System (AFAS). However, after about 40 seconds of operation the 2C AFW pump tripped inexplicably on overspeed. Both of the 2A and 2B AFW motor-driven pumps started and ran normally. At the end of the report period, the licensee had initiated CR 03-4548 and assembled a root cause team to investigate what appeared to be a repeat failure of the April 1, 2003 event. The implications of this issue as a potential finding and its safety significance will be addressed in a subsequent report after the licensee has completed their root cause determination. Until then, this issue will be tracked as URI 0500389/2003007-02, Repetitive Overspeed Failures of the 2C AFW Pump.

.5 Unit 2 Notice of Enforcement Discretion (NOED)

On November 20, the 1B and 2B Startup Transformers (SUT) were removed from service for scheduled online maintenance which required entering into a 72 hour TS 3.8.1.1. action statement for both units. The scheduled duration for this critical maintenance management (CMM) evolution was 48 hours. However, during the CMM, the licensee discovered that several of the 230 KVAC insulator supports on the 2B SUT were badly degraded and could not be repaired. The licensee also ascertained that replacement supports could not be fabricated and installed within the allowed outage time (AOT) of 72 hours. In addition, due to breaker performance problems, the licensee was unable to align the 1B SUT to unit 2 that would have allowed exiting TS 3.8.1.1 Action a. by entering Action f. Consequently, on November 22, 2003, the licensee requested enforcement discretion for an additional 72 hours beyond the allowed outage time of TS 3.8.1.1 Action a. in order to repair the 2B SUT. The NRC approved this request verbally late that same day. However, on November 23, prior to the expiration of the original 72 hours, the licensee was able to resolve the problems with the 1B/2B SUT crosstie breaker and successfully align the 1B SUT according to TS 3.8.1.1 Action f. and thereby exit the 72 hour limiting action statement. As such, the licensee did not actually utilize the NOED.

4OA6 Meetings

Exit Meeting Summary

The inspectors presented the inspection results to Mr. Bill Jefferson and other members of licensee management on January 5, 2004. Several interim exits were held during the report periods by regional inspectors. The licensee acknowledged the findings presented. No proprietary information was identified.

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

D. Calabrese, Emergency Planning Supervisor
D. Pitts, Instrumentation and Controls Department Supervisor
R. De La Espriella, Site Quality Manager
R. Hughes, Site Engineering Manager
M. Wolaver, Acting Systems & Component Engineering Manager
W. Jefferson, Site Vice President
J. Kirkpatrick, Maintenance Manager
C. Costanzo, Operations Manager
R. McDaniel, Fire Protection Supervisor
D. Mohre, Maintenance Rule Administrator
E. Cartwright, Projects Manager
T. Patterson, Licensing Manager
J. Porter, Operations Support Engineering Manager
A. Pell, Training Manager
G. Johnston, Plant General Manager
J. Martin, Operations Support Supervisor
G. Varnes, Security Supervisor
S. Wisla, Health Physics Manager

Other licensee employees contacted include office, operations, engineering, maintenance, chemistry/radiation, and corporate personnel.

NRC personnel

B. Moroney, NRR Project Manager

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000389/2003007-02	URI	Repetitive Overspeed Failures of the 2C AFW Pump (Section 4OA3.4)

Opened and Closed

05000335/2003007-01	NCV	Failure To Maintain Spray Additive Tank NaOH Concentration Within TS Limits (Section 4OA2.2)

Closed

0500389/2003-002-00	LER	Two Flaws Identified During Reactor Pressure Vessel Head Inspections (Section 4OA3.2)
05000335/2003-004-00	LER	Operation of NaOH Tank Outside TS Limits (Section 4OA3.1)

LIST OF DOCUMENTS REVIEWED

4OA2: Identification and Resolution of Problems

Speak Out files:

NSS-PSL-01-009, 013, 022, 028, 029, 032, 044, 047, 055, 067, and 073

NSS-PSL-02-006, 010, 015, 017, 019, and 024

NSS-PSL-03-001, 003 - 008, 010, 012 - 014, 016, 017, 026, 031, 032, 035, and 036

Condition Reports:

01-1154

02-1194, and 2689

03-0979, 1482, 1790, 1984, 2146, and 2823

Other Documents:

Agenda For CNRB Meeting #515

St. Lucie Plant CR Program Participation Weekly Indicator (11/5 - 11/11/03)

Training material for “Lessons Learned from the Davis Besse Event”

SOER 02-04 Self-Assessment Report (July 21-24, 2003)