UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
245 PEACHTREE CENTER AVENUE NE, SUITE 1200
ATLANTA, GEORGIA 30303-1257

October 29, 2010

Mr. Mano Nazar
Executive Vice President and Chief Nuclear Officer
Florida Power and Light Company
P.O. Box 14000
Juno Beach, FL 33408-0420

SUBJECT: TURKEY POINT NUCLEAR PLANT – INTEGRATED INSPECTION REPORT 05000250/2010004 AND 05000251/2010004; 07200062/2010002

Dear Mr. Nazar:

On September 30, 2010, the US Nuclear Regulatory Commission (NRC) completed an inspection at your Turkey Point Units 3 and 4. The enclosed integrated inspection report documents the inspection findings which were discussed on October 13, 2010, with Mr. M. Kiley and other members of your staff.

The inspection examined activities conducted under your license as they related 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, one self-revealing finding of low safety significance (Green) was identified. The 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) consistent with the NRC Enforcement Policy. Also, four licensee-identified violations, which were determined to be of very low safety significance, are listed in Section 4OA7 of this report. If you wish to 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 20555-001, 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 Resident Inspector at Turkey Point. In addition, if you disagree with the cross-cutting aspect assigned to any finding in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your disagreement, to the Regional Administrator, Region II, and the NRC Resident Inspector at Turkey Point.

In accordance with 10 CFR 2.390 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 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/

Daniel W. Rich, Branch Chief
Reactor Projects Branch 3
Division of Reactor Projects

Docket Nos.: 50-250, 50-251, 07200062
License Nos.: DPR-31, DPR-41

Enclosure: Inspection Report 05000250/2010004 and 05000251/2010004;
07200062/2010002

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Letter to Mano Nazar from Daniel W. Rich dated October 29, 2010

SUBJECT: TURKEY POINT NUCLEAR PLANT – INTEGRATED INSPECTION REPORT 05000250/2010004 AND 05000251/2010004; 07200062/2010002

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U.S. NUCLEAR REGULATORY COMMISSION

REGION II

Docket Nos.:	50-250, 50-251, 07200062
License Nos.:	DPR-31, DPR-41
Report No.:	05000250/2010004, 05000251/2010004, 07200062/2010002
Licensee:	Florida Power & Light Company (FPL)
Facility:	Turkey Point Nuclear Plant, Units 3 & 4
Location:	9760 S. W. 344th Street Florida City, FL 33035
Dates:	July 1 to September 30, 2010
Inspectors:	S. Stewart, Senior Resident Inspector M. Barillas, Resident Inspector R. Chou, Reactor Inspector (Section 1R07) R. Carrion, Senior Reactor Inspector (Section 4OA5.2) C. Fletcher, Senior Reactor Inspector (Section 4OA5.2) W. Rogers, Senior Reactor Analyst (Section 4OA7)
Approved by:	D. Rich, Chief Reactor Projects Branch 3 Division of Reactor Projects

Enclosure

SUMMARY OF FINDINGS

IR 05000250/2010004, 05000251/2010004, IR 07200062/2010002, 7/1/2010 – 9/30/2010; Turkey Point Nuclear Power Plant, Units 3 and 4; Maintenance Effectiveness

The report covered a three-month period of inspection by resident inspectors and region based inspectors. 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 cross-cutting aspect is determined using IMC 310, Components Within The Cross-Cutting Areas. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 4, dated December, 2006.

A. NRC-Identified & Self-Revealing Findings

Cornerstone: Initiating Events

(Green) A self-revealing non-cited violation (NCV) of 10 CFR 50 Appendix B, Criterion V, Instructions, Procedures, and Drawings, was identified when the licensee started corrective maintenance on the Unit 4 reactor protection system with an inadequate procedure. As a result, a reactor trip occurred when a reactor trip circuit was not placed on bypass as an initial condition needed to safely complete the work. During the event investigation, the licensee determined that neither the work order, nor the pre-job review identified the need to place the affected train of the reactor protection system on the bypass breaker.

The finding was determined to be more than minor because it affects the Initiating Events cornerstone attribute of procedure quality and adversely affected the cornerstone objective to limit the likelihood of an event that upsets plant stability by resulting in a reactor trip. The finding was evaluated in accordance with IMC 0609, Attachment 4, and determined to be of very low safety significance (Green) per SDP Phase 1 determination because the finding did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions would not be available. This finding has a cross-cutting aspect in the area of Human Performance, Work Control H.3(b) because the licensee did not appropriately coordinate work activities by incorporating actions to address the need to keep personnel apprised of the operational impact of work and plant conditions that may affect work activities, resulting in a reactor trip. (1R12)

B. Licensee Identified Violations

Violations of very low safety significance, identified by the licensee, have been reviewed by the inspectors. Corrective actions taken or planned by the licensee have been entered into the licensee's corrective action program. These violations and corrective actions are listed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status:

Unit 3 began the period at full power. Reactor power was reduced to less than 60 percent on September 7, 2010, due to a secondary system transient. Full reactor power was restored later the same day. On September 23, Unit 3 tripped from full power due to an electrical fault on the main transformer (EN46274). The reactor remained shut down and a cooldown commenced on September 25 to start refueling outage 25. The reactor remained shutdown at the end of the period.

Unit 4 began the period at full power. Unit 4 reactor power was reduced to 40 percent on August 26, 2010 for secondary valve testing, returning to full power on August 27. On September 8, Unit 4 tripped from full power during reactor protection system maintenance (EN46235). On September 9, during a planned reactor startup, the reactor trip breakers were opened in accordance with technical specifications because of failure of one rod group position indicator (EN46246). The reactor was restarted later on September 9 and returned to full power on September 10. On September 21, Unit 4 tripped from full power during reactor protection system testing (EN46265). The reactor was restarted on September 24 and returned to full power later that day. Unit 4 operated at full power for the remainder of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity (Reactor-R)

1R01 Adverse Weather Protection (02.03 Readiness for Impending Adverse Weather Conditions)

a. Inspection Scope

On July 22-23, 2010, the inspectors reviewed the licensee's preparations for Tropical Storm Bonnie per licensee procedure 0-ONOP-103.3, Severe Weather Preparations. The inspectors toured the protected area and exterior plant grounds for loose debris which could pose hazards to plant equipment during high winds. The inspectors selected risk-significant and susceptible systems and areas for review and verified readiness of essential systems. No severe weather conditions were experienced at the site. The following areas of the site were specifically inspected:

- Main switchyard
- Unit 3 and Unit 4 Intake areas
- Unit 3 and Unit 4 Emergency Diesel Generator and Oil Tank areas
- Unit 3 and Unit 4 Component Cooling Water Pump areas
- Unit 3 and Unit 4 RWST areas

b. Findings

No findings were identified.

1R01 Adverse Weather Protection (02.03, Evaluate Readiness for Impending Adverse Weather Conditions)

a. Inspection Scope

The inspectors evaluated the implementation of licensee off-normal procedure 0-ONOP-011.1, Intake Canal High Temperature when the intake cooling water exceeded 96 degrees Farenheit (F) which coincided with recurring high containment ambient temperatures during the week of August 15, 2010. The inspectors verified that Technical Specification 3.6.1.5 high temperature equivalent hours were recorded and tracked.

b. Findings

No findings were identified.

1R04 Equipment Alignment

.1 Partial Equipment Walkdowns

a. Inspection Scope

The inspectors conducted three partial alignment verifications of the safety-related systems listed below. These inspections included reviews using plant operating procedures and piping and instrumentation drawings, which were compared with observed equipment configurations to verify as best possible that the critical portions of the systems were correctly aligned to support operability. The inspectors also verified that the licensee had identified and resolved equipment alignment problems that could cause initiating events or impact the capability of mitigating systems or barriers by entering them into the corrective action program.

- July 22, 2010: Unit 3 Component Cooling Water Pumps 3B and 3C flowpath verification using procedures 3-OSP-030.3, Component Cooling Water System Flowpath Verification; and 3-OP-005, 4160 Volt Buses A,B, and D, while component cooling water pump A was removed from service for a motor inspection under work order 39013031-01
- August 16, 2010: Unit 3, Train 2 auxiliary feedwater using licensee procedure 3-NOP-075, Auxiliary Feedwater System; while Train 1 AFW was out of service for planned maintenance under work order 39025733-01. Selected portions of Unit 4 auxiliary feedwater were also checked by the inspectors.
- September 15, 2010: Unit 4, Train 2 of auxiliary feedwater using licensee procedure 4-NOP-075, Auxiliary Feedwater System; while both trains of standby steam generator feedwater were removed from service for suction line maintenance.

b. Findings

No findings of significance were identified.

.2 Complete System Walkdown

a. Inspection Scope

The inspectors conducted a detailed review of the alignment and condition of the standby steam generator feedwater system (SBSG) to verify that the existing alignment of the system was consistent with the design. To determine the correct system alignment, the inspectors reviewed the plant Technical Specifications (TS), procedures, drawing, and the Final Safety Analysis Report (FSAR). Plant drawing 5610-M-3074, Standby Steam Generator Feedwater, and licensee procedure 0-NOP-074.01, Standby Steam Generator Feedwater System, were specifically used to do the walkdown. The inspectors walked down the system and reviewed the following:

- Valves were correctly positioned and did not exhibit leakage that would impact the functions of any given valve.
- Electrical power was available for the motor driven SBSG feedwater pump.
- Major system components were correctly labeled, lubricated, cooled, ventilated, etc.
- Hangers and supports were installed and functional.
- Essential support systems were operational.
- Ancillary equipment or debris did not interfere with system performance.
- Valves were locked as required by the locked valve program.

Design and equipment issues were reviewed to determine if the identified deficiencies significantly impacted the system's functions. Items included in this review were the system health report for system 74B, the system description, pump vibration data, condition reports, and outstanding maintenance work orders (WOs). In addition, the inspectors reviewed the licensee's corrective action program to ensure that the licensee was identifying and resolving equipment alignment problems in a timely manner.

b. Findings

No findings were identified.

1R05 Fire Protection

a. Inspection Scope

.1 Fire Area Walkdowns

The inspectors toured the following six plant areas during this inspection period to evaluate conditions related to control of transient combustibles and ignition sources. The material condition and operational status of fire protection systems including fire barriers used to prevent fire damage or fire propagation were also checked. The inspectors reviewed these activities against provisions in the licensee's procedure 0-ADM-016, Fire Protection Plan, and 10 CFR Part 50, Appendix R. The licensee's fire impairment lists were routinely reviewed. In addition, the inspectors reviewed the condition report database to verify that fire protection problems were being identified and

appropriately resolved. The inspectors routinely reviewed the fire impairments list and checked that compensatory actions were appropriate. The following areas were inspected:

- Auxiliary building breezeway
- Unit 3 main feedwater platform
- Fire Zone 62- Units 3 and 4 Computer Room
- Fire Zone 93- Unit 4 480V Load Centers A and B Room
- Main control room
- 3B battery room

b. Findings

No findings were identified.

1R07 Heat Sink Performance (71111.07T)

.1 Triennial Review of Heat Sink Performance

a. Inspection Scope

The inspectors reviewed operability determinations, completed surveillances, calculations, performance test results, and inspection results associated with the Unit 3 Component Cooling Water heat exchanger (CCW HX) 3E207B, the Unit 3 Residual Heat Removal heat exchanger (RHR HX) 3E206A, the Unit 4 Containment Spray Pump Seal Water heat exchanger 4P214A, and the Ultimate Heat Sink (UHS) of Canal System. These heat exchangers or UHS were chosen based on their risk significance in the licensee's probabilistic safety analysis, their important safety-related mitigating system support functions, and their relatively low margin.

The inspectors determined whether test, inspection, maintenance, and monitoring of biotic fouling and macrofouling programs were adequate to ensure proper heat transfer. This was accomplished by determining whether the test method used was consistent with accepted industry practices, or equivalent, the test conditions were consistent with the selected methodology, the test acceptance criteria were consistent with the design basis values, and reviewing results of heat exchanger performance testing. The inspectors also determined whether the test results appropriately considered differences between testing conditions and design conditions, the frequency of testing based on trending of test results was sufficient to detect degradation prior to loss of heat removal capabilities below design basis values, and whether test results considered test instrument inaccuracies and differences.

The inspectors reviewed the methods and results of heat exchanger performance inspections. The inspectors determined whether the methods used to inspect and clean heat exchangers were consistent with as-found conditions identified and expected degradation trends and industry standards, the licensee's inspection and cleaning activities had established acceptance criteria consistent with industry standards, and the

as-found results were recorded, evaluated, and appropriately dispositioned such that the as-left condition was acceptable.

The inspectors determined whether the condition and operation of the heat exchangers were consistent with design assumptions in heat transfer calculations and as described in the final safety analysis report. This included determining whether the number of plugged tubes was within pre-established limits based on capacity and heat transfer assumptions. The inspectors determined whether the licensee evaluated the potential for water hammer and established adequate controls and operational limits to prevent heat exchanger degradation due to excessive flow induced vibration during operation. In addition, eddy current test reports and visual inspection records were reviewed to determine the structural integrity of the heat exchanger.

The inspectors determined whether the performance of the Intake Cooling Water (ICW) system and its subcomponents such as piping, intake screens, pumps, valves, etc. was appropriately evaluated by tests or other equivalent methods to ensure availability and accessibility to the in-plant cooling water systems.

The inspectors rode a boat to examine the canal and embankment condition of the inlet and outlet canal system which the outlet canal connected to the inlet canal to form a closed system. The outlet canal system was the UHS and the inlet canal provided the ICW. The inspectors determined whether the licensee's inspection of the UHS was thorough and of sufficient depth to identify degradation of the canal bank protection or loss of structural integrity. This included determination whether vegetation present along the slopes was trimmed, maintained and was not adversely impacted by the embankment. In addition, the inspectors determined whether the licensee ensured sufficient reservoir capacity by trending and removing debris or sediment buildup in the UHS.

The inspectors performed a system walkdown on the CCW system, which included the pumps, piping, valves, instruments, and heat exchangers to determine whether the licensee's assessment on structural integrity was adequate. In addition, the inspectors reviewed available licensee's testing and inspection results to identify any adverse trends since the last NRC inspection. The inspectors discussed with the system engineer to identify adverse trends that could be indicative of excessive leakage out of the CCW system. For buried or inaccessible piping, the inspectors reviewed the licensee's pipe testing, the crawl-through inspection reports, and monitoring program to determine whether structural integrity was ensured and that any leakage or degradation was appropriately identified and dispositioned by the licensee.

The inspectors performed a system walkdown of the intake cooling water (ICW) system and structure to determine whether the licensee's assessment on structural integrity and component functionality was adequate and that the licensee ensured proper functioning of traveling screens and strainers and structural integrity of component. In addition, the inspectors determined whether the ICW pump bay and travel screen area silt accumulation was monitored, inspected, trended, removed, and maintained at an acceptable level by the licensee, and that water level instruments were functional and

routinely monitored. The inspectors also determined whether the licensee's ability to ensure functionality during adverse weather conditions was adequate.

In addition, the inspectors reviewed condition reports related to the heat exchangers and heat sink performance issues to determine whether the licensee had an appropriate threshold for identifying issues and evaluating the effectiveness of the corrective actions.

These inspection activities constituted four heat sink inspection samples as defined in IP 71111.07. The documents that were reviewed are included in the Attachment to this report.

b. Findings

No findings were identified.

1R11 Licensed Operator Requalification Program

a. Inspection Scope

On July 30, 2010, the inspectors observed and assessed licensed operator continuing training remediation in the plant specific simulator. The simulated events were done using Nuclear Training Department Training Evaluation Scenario 750207606, Loss of All AC/Steam Generator Tube Rupture, dated July 30, 2010. The inspectors observed the operator's use of procedures 3-EOP-E-0, Reactor Trip and Safety Injection; 3-EOP-ECA-0.0, Loss of All AC Power; and 3-ONOP-071.2, Steam Generator Tube Rupture. The operators' actions were checked to be in accordance with licensee procedures. Appropriate completion of three crew critical tasks were verified; manual initiation of safety injection, isolation of feedwater flow to the faulty steam generator, and re-establishing one AC bus using manual actions. Because the remediation exam did not include a shift manager, no event classifications were made. The simulator board configurations were compared with actual plant control board configurations. The inspectors specifically evaluated the following attributes related to operating crew performance and the licensee evaluation:

- 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 off-normal and emergency operating procedures; and emergency plan implementing procedures
- Control board operation and manipulation, including high-risk operator actions
- Oversight and direction provided by supervision, including ability to identify and implement appropriate technical specification actions
- Overall crew performance and interactions
- Evaluator's critique and findings

b. Findings

No findings were identified.

1R12 Maintenance Effectiveness

a. Inspection Scope

The inspectors reviewed four equipment problems and associated condition reports listed to verify that the licensee's maintenance efforts met the requirements of 10 CFR 50.65 (Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants) and station procedure NAP-415, Maintenance Rule Program Administration. The inspectors' efforts focused on maintenance rule scoping, characterization of maintenance problems and failed components, risk significance, determination of (a)(1) classification, corrective actions, and the appropriateness of established performance goals or monitoring criteria. The inspectors reviewed the action plan and the (a)(2) reclassification for the systems placed in (a)(1). The inspectors also interviewed responsible engineers and observed some of the corrective maintenance activities. The inspectors verified that equipment problems were being identified and entered into the corrective action program. The inspectors used licensee engineering procedure EDI-ENG-025, Management and Administration of Maintenance Rule Processes, and the applicable system health reports in the reviews.

- Condition Report 2010-7013, Unit 3 B EDG diesel oil transfer pump failure
- Condition Report 2010-12306, Unit 4 A EDG Lockout
- Condition Report 2006-34852, Unit 4 Containment Purge POV-4-2602 isolation valve failed to close due to corrosion on valve actuator
- Condition Report 2009-33606, Two shutdown bank B control rods dropped into the core during rod position indication testing

b. Findings

Introduction: A Green self-revealing non-cited violation (NCV) of very low safety significance was identified when the licensee initiated corrective maintenance on the Unit 4 reactor protection system with an inadequate procedure. As a result, a reactor trip occurred when a reactor trip circuit was not placed on bypass as needed to support the maintenance.

Description: On September 8, 2010, during routine reactor protection system testing, a turbine trip relay in the reactor protection system was identified as binding in the tripped condition. Emergent work order 39011941-01 was prepared and authorized to replace the defective 4-SL-X-B relay in the B train of reactor protection. The work order instruction did not state that the B reactor trip bypass breaker needed to be shut to prevent a reactor trip when leads were lifted to replace the relay as specified for the maintenance. Subsequently at 1345 hours, technicians completing the work lifted a lead from the relay. The lifted lead de-energized a second relay in the trip logic circuit thus making up trip logic which opened the B reactor trip breaker causing a Unit 4 reactor trip.

NRC inspectors responded to the trip and observed plant operators stabilize the reactor in Mode 3 using emergency operating procedures. Control rods were inserted, auxiliary feedwater actuated as designed, and there were no complications. The licensee made a 50.72 report to NRC.

The licensee documented the trip in the corrective action program (AR 578460) and initiated a root cause evaluation. The investigation found that the reactor trip bypass breaker needed to be shut to safely perform the relay replacement. Neither the work order, nor the pre-job review identified the need to place the affected train of the reactor protection system on the bypass breaker. As an immediate corrective action, the licensee specified that all maintenance requiring replacement of a reactor protection relay would require the associated reactor trip bypass breaker to be closed when in operational modes 1 or 2. Additional corrective actions are being considered.

Analysis: The performance deficiency associated with this finding was that the licensee did not provide adequate work instructions for replacing 4B reactor protection relay 4-SL-X-B with the reactor operating at power. As a result, when the work was performed in accordance with the instructions, a reactor trip occurred. The finding was determined to be more than minor because it affected the Initiating Events cornerstone attribute of procedure quality and adversely affected the cornerstone objective to limit the likelihood of an event that upsets plant stability by resulting in a reactor trip. The finding was evaluated in accordance with IMC 0609, Attachment 4, and determined to be of very low safety significance (Green) per SDP Phase 1 determination because the finding did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions would not be available. This finding has a cross-cutting aspect in the area of Human Performance, Work Control H.3(b) because the licensee did not appropriately coordinate work activities by incorporating actions to address the need to keep personnel apprised of the operational impact of work and plant conditions that may affect work activities, resulting in a reactor trip.

Enforcement: 10 CFR 50 Appendix B, Criterion V, Instructions, Procedures, and Drawings, requires, in part, that activities affecting quality be prescribed by documented instructions of a type appropriate to the circumstances. Contrary to the requirement, on September 8, 2010, work order 39011941-01, Unit 4 Reactor Protection System Relays, Troubleshooting and Repair, which documented instructions for replacing reactor protection relay 4-SR-X-B, was not appropriate to the circumstances when the procedure failed to establish an initial condition of the associated reactor trip bypass breaker being closed prior to the work. As a result, a reactor trip occurred when leads to the relay were lifted as specified by the work order. The Unit 4 trip was documented in AR 578460. During the subsequent investigation of the event, the licensee found the missed initial condition and specified that future replacements of reactor protection relays would require, as a prerequisite, the associated reactor trip bypass breaker to be closed. Because this finding was of very low safety significance (Green) and has been entered into the licensee corrective action program, this violation is being treated as a Non-cited violation (NCV), consistent with the NRC Enforcement Policy. (NCV 05000250,251/2010-004-01, Failure to provide adequate instructions when working on the reactor protection system results in reactor trip.)

1R13 Maintenance Risk Assessments and Emergent Work Control

a. Inspection Scope

The inspectors completed in-office reviews and control room inspections of the licensee's risk assessment of six emergent or planned maintenance activities. The inspectors verified the licensee's risk assessment and risk management activities using the requirements of 10 CFR 50.65(a)(4); the recommendations of Nuclear Management and Resource Council 93-01, Industry Guidelines for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants, Revision 3; and Procedures 0-ADM-068, Work Week Management and 0-ADM-225, On Line Risk Assessment and Management. The inspectors also verified the licensee evaluated aggregate risk using FPL procedure OP-AA-104-1007, Online Aggregate Risk. The inspectors reviewed the effectiveness of the licensee's contingency actions to mitigate increased risk resulting from the degraded equipment. The inspectors evaluated the following risk assessments during the inspection:

- July 7, 2010, Unit 3 risk assessment and management during cycling of RHR valve 3-757C, RHR Heat Exchanger B bypass head isolation valve
- July 13, 2010, Unit 3 risk assessment after failure of Eagle 21, Channel 2 (white)
- July 22, 2010, risk assessment during cycling of High Head Safety Injection MOV-3-878B unit 3 and unit 4 cross-connect valve following maintenance under WO 38002456
- July 28, risk management when channel 2 of Eagle 21 failed, placing Unit 3 in a partial trip-logic condition (AR 570004). Moderator Temperature Coefficient testing was delayed pending restoration of full protection logic.
- August 16, 2010, Unit 3 and 4 risk management while Train 1 of auxiliary feedwater was out of service for planned maintenance.
- September 15, 2010, Unit 4 risk management when component cooling water headers were split due to potential impact of a heavy load in vicinity of piping.

b. Findings

No findings were identified.

1R15 Operability Evaluations

a. Inspection Scope

For the six operability evaluations described in the condition reports (CR/AR) listed below, the inspectors evaluated the technical adequacy of licensee evaluations to ensure that TS operability was properly justified and the subject component or system remained available such that no unrecognized increase in risk occurred. The inspectors reviewed the final safety analysis report and the maintenance rule data base to verify system functions. In addition, when applicable, the inspectors reviewed compensatory measures implemented to verify that the plant design basis was being maintained. The

inspectors also reviewed a sampling of condition reports to verify that the licensee was identifying and correcting any deficiencies associated with operability evaluations.

- CR 2010-16082, 4A Load Sequencer Trouble Alarm received in the control room
- AR 568986, Unit 3 CSP 3-907A active bonnet leak
- AR 572166, Unit 3 A Fuel oil transfer pump did not show a level increase when attempting to fill the 4B Fuel Oil Storage Tank. The licensee demonstrated the pump filled the 3A fuel oil day tank from the Unit 3 Fuel Oil Storage Tank using 0-OSP-023.3, to verify operability.
- AR 571501, Heat stress during fire drill
- AR 576946, 3A component cooling pump motor makes an unusual noise on startup
- AR 577944, Plywood found installed on 3B and 4A station batteries

b. Findings

No findings were identified.

1R19 Post Maintenance Testing

a. Inspection Scope

For the five post maintenance tests listed below, the inspectors reviewed the test procedures and either witnessed the testing and/or reviewed test records to determine whether the scope of testing adequately verified that the work performed was correctly completed and demonstrated that the affected equipment was functional and operable. The inspectors verified that the requirements of Procedure 0-ADM-737, Post Maintenance Testing, were incorporated into test requirements. The inspectors reviewed the following work orders (WO) and/or surveillance procedures (OSP):

- Unit 3, Continuity check using Work Order 39002398, following 3A emergency diesel generator fuel transfer level control circuit fuse replacement (Drawing 5613-E-27, Mechanical Auxiliaries, Fuel Oil Transfer was used)
- Unit 4, 4-OSP-019.1, Intake Cooling Water Inservice Test after replacement of 4B intake cooling water pump discharge check valve per work order 39013348-01
- Common, Turbine overspeed testing of the A auxiliary feedwater pump in accordance with 4-OSP-075.9, AFW Overspeed Test after replacing the intake check valve (foot valve) on the pump P2A lube oil system under work order 39025733-01
- Unit 3, 3-OSP-030.1, Component Cooling Water Pump Inservice Test and 3-OSP-030.3, Component Cooling Water System Flowpath Verification, following 3A component cooling pump bearing replacement under work order 40005363-01
- Common, Turbine testing of the A auxiliary feedwater pump in accordance with 4-OSP-075.5, AFW Train 1 Operability Verification after replacing the intake check valve (foot valve) on the pump P2A lube oil system under work order 39025733-02 (rework)

b. Findings

No findings were identified.

1R22 Surveillance Testing

a. Inspection Scope

The inspectors either reviewed or witnessed the following six surveillance tests to verify that the tests met the Technical Specifications, the UFSAR, the licensee's procedural requirements, and that the tests demonstrated the systems were capable of performing their intended safety functions as well as their operational readiness. In addition, the inspectors evaluated the effect of the testing activities on the plant to ensure that conditions were adequately addressed by the licensee staff and that after completion of the testing activities, equipment was returned to the positions/status required for the system to perform its safety function. The tests reviewed included an inservice test (IST) and one reactor coolant system leakage detection surveillance per unit. The inspectors verified that surveillance issues were documented in the corrective action program.

- Unit 3, 3-OSP-023.1, Diesel Generator Operability Test (3B) following 3-OSP-300.3, Section 7.6.21, Test of 3B EDG Breaker 3AB20
- Unit 4, 4-OSP-023.1, Diesel Generator Operability Test (4B) following quarterly preventive maintenance using 4-PMM-022.26 (Work Order 40001617-01)
- Unit 4: 4-OSP-075.1, Auxiliary Feedwater Train 1 Operability Verification
- Unit 3, 0-OSP-062.2, Safety Injection System Inservice Test (3A safety injection pump and check valve test) FPL Drawing 5613-M-3062, Safety Injection System was used by the inspector (IST)
- Unit 3, 3-OSP-040.12, At Power Measurement of Moderator Temperature Coefficient
- 0-OSP-074.3, B Standby Steam Generator Feedwater Pump Availability Test

b. Findings

No findings were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification

Initiating Events and Mitigating Systems Cornerstones

a. Inspection Scope

The inspectors checked licensee submittals for the performance indicators (PIs) listed below for the period July 1, 2009, through June 30, 2010, to verify the accuracy of the PI data reported during that period. Performance indicator definitions and guidance contained in NEI 99-02, "Regulatory Assessment Performance Indicator Guideline," Rev. 6 and licensee procedure 0-ADM-032, "NRC Performance Indicators Turkey Point," were

used to check the reporting for each data element. The inspectors checked licensee event reports (LERs), operator logs, plant status reports, condition reports (CRs), and performance indicator data sheets to verify that the licensee had identified the cumulative safety system unavailability and required hours, as applicable. The inspectors interviewed licensee personnel associated with performance indicator data collection, evaluation, and distribution.

- Unit 3 Unplanned Scrams per 7000 Critical Hours
- Unit 3 Unplanned Scrams with Complications
- Unit 3 Unplanned Power Changes per 7000 Critical Hours
- Unit 3 Safety System Functional Failures
- Unit 3, Mitigating Systems Performance Indicator (MSPI) Emergency AC Power
- Unit 3, MSPI High Head Safety Injection
- Unit 3, MSPI Residual Heat Removal System
- Unit 3, MSPI Auxiliary Feedwater System
- Unit 3, MSPI Cooling Water Support Systems
- Unit 4 Unplanned Scrams per 7000 Critical Hours
- Unit 4 Unplanned Scrams with Complications
- Unit 4 Unplanned Power Changes per 7000 Critical Hours
- Unit 4 Safety System Functional Failures
- Unit 4, MSPI Emergency AC Power
- Unit 4, MSPI High Head Safety Injection
- Unit 4, MSPI Residual Heat Removal System
- Unit 4, MSPI Auxiliary Feedwater System
- Unit 4, MSPI Cooling Water Support Systems

b. Findings

No findings were identified.

4OA2 Problem Identification and Resolution

.1 Daily Review

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 screening of items entered daily into the licensee's corrective action program. This review was accomplished by reviewing daily printed summaries of condition reports and by reviewing the licensee's electronic condition report database. Additionally, reactor coolant system unidentified leakage was checked on a daily basis to verify no substantive or unexplained changes.

b. Findings

No findings were identified.

.2 Annual Sample Review

a. Inspection Scope

The inspectors selected the following condition report for detailed review and discussion with the licensee. The condition report was reviewed to ensure that an appropriate evaluation was performed and appropriate corrective actions were specified and prioritized. Other attributes checked included disposition of operability, resolution of the problem including cause determination and corrective actions. The inspectors evaluated the condition report in accordance with the requirements of the licensee's corrective actions process as specified in licensee procedures, PI-AA-204, Condition Identification and Screening Process; and PI-AA-205, Condition Evaluation and Corrective Action.

- CR 2009-13740, Failure to run of 4B emergency diesel generator

b. Findings

No findings were identified.

4OA3 Event Follow-up

.1 Unit 3 Rapid Power Reduction – September 7; Unit 3 Reactor Trip September 23; Unit 4 Reactor Trip, September 8 and September 21

The inspectors observed and reviewed plant transients to provide input to the NRC decision making process regarding the need for a special or augmented NRC inspection. Further, the inspectors reviewed personnel performance during the non-routine plant events and transient operations to determine if the response was appropriate and in accordance with plant procedures and training.

b. Findings

No findings were identified.

.2 (Closed) Licensee Event Report (LER) 50-251/2009-001-00, 4B Emergency Diesel Generator Inoperable Due to Air-bound Main Fuel Pump.

On August 11, 2009, during a surveillance test of the 4B emergency diesel generator, erratic fuel pressure indication was observed and the DC priming pump remained running beyond the time when it would normally shut off. The test was stopped and an investigation started. Within a few hours, operators shifted to the alternate north fuel oil suction strainer (duplex unit), and successfully completed the surveillance test. Further investigation found air in-leakage in the south suction strainer that caused air binding of the shaft driven fuel oil pump. As corrective action, the entire strainer assembly was replaced, like for like, the source of air in-leakage was verified by vacuum testing of the removed strainer assembly, and the diesel was tested satisfactorily. In the longer term, the licensee planned a modification to lower the strainer assembly below the level of the fuel oil day tank which would prevent in-leakage should a faulty/leaking strainer gasket

condition occur. The licensee considered the risk significance of the failure to be very low because the running DC priming pump would allow the diesel to carry the expected bus loading for many loss of power scenarios and operators could complete load management for the more severe cases. The licensee used daily operator logs of fuel oil priming pressure to determine the date when the air binding most likely occurred, that being July 28, 2009. As such, the engine was out of service for 14.3 days, beyond the 14 day allowed outage time in plant technical specifications. Enforcement regarding this issue is provided in Section 4OA7 of this report. The LER is closed.

.3 (Closed) Licensee Event Report (LER) 50-251/2010-001-00, Two Shutdown Bank Rods Were Dropped from the Fully Withdrawn Position

On November 26, 2009, during testing of the Unit 4 rod position indication system and while withdrawing control rod banks A and B, two shutdown bank rods, H6 and H10, dropped into the core. The reactor was initially shutdown and remained shutdown during the event. Plant operators investigated the dropped rods, verified that the problems were not with the recently replaced rod position indication system, then tripped the reactor in accordance with off-normal procedures. The issue was documented in the corrective action program as CR 2009-33606 and an investigation of the cause conducted. The apparent cause was a corroded connection possibly assisted by a loose connector in the rod control circuitry that caused a voltage drop thus allowing an insufficient holding voltage on the stationary grippers of the affected rods. FPL replaced the circuit cards associated with regulation of current in this group of rods and cleaned/tightened the associated electrical connections. Enforcement action associated with this event was documented in NRC Inspection Report 05000250,251/2010-006. The LER is closed.

.4 (Closed) Violation SL IV 05000250, 251/2008-005-01, Failure to Accomplish an Activity Affecting Quality in Accordance With Procedures

NRC issued a Severity Level (SL) IV violation to FPL on December 23, 2008, for failure to accomplish an activity affecting quality in accordance with procedures. Specifically, a supervisor failed to follow licensee procedure 0-OSP -040.8, Reactivity Deviation from Design Calculation, when he reviewed and approved an incorrect (i.e., not current) boron sample that was collected several hours before the reactivity calculation was performed. FPL responded to the Notice of Violation (EA-08-252) with a letter dated January 22, 2009. In the letter, FPL agreed that the violation occurred as stated; however, FPL disagreed with the NRC's conclusion that the violation was willful. After review and consideration of FPL's response, NRC issued a letter to FPL dated March 25, 2009, providing reasons and concluded that the violation occurred as stated in the Notice of Violation, and that it was willful. The inspectors reviewed FPL's response letter, condition reports (CRs) 2006-6079 and 2006-20748, and operations surveillance procedure no. 0-OSP-040.8. The inspectors determined that reason for violation was appropriately addressed; corrective actions were implemented and full compliance was achieved. Therefore, this violation is closed.

.5 (Closed) Licensee Event Report (LER) 50-250/2010-002-00, Fuel Transfer Pump Failure Renders 3B Emergency Diesel Generator Inoperable

On June 7, 2010, during a surveillance test of the 3B emergency diesel generator, the 3B fuel transfer pump failed to start with a low level in the 3B fuel oil day tank. The cause of the failure was binding of the pump shaft due to inadequate bearing lubrication. The licensee documented the failure in the corrective action program as CR 406564 and started an investigation. The licensee identified that the pump shaft was difficult to rotate and there had been no preventive maintenance to lubricate the transfer pump bearings. Because of this, binding of the shaft due to lack of lubrication was the cause of the failure. The pump was replaced under work order 40011161-02 and the licensee was developing a preventive maintenance activity to periodically lubricate the bearings. The inspector verified that the 3B EDG day tank could be filled using any of the other fuel oil transfer pumps (3A, 4A, or 4B) in accordance with licensee procedure ¾-NOP-022, EDG Fuel Oil System. Because of this capability, the failure of the transfer pump was characterized as having very low safety significance (Green). The licensee could not determine the exact time of the transfer pump failure and assumed (using t/2) an out of service time of about 1.5 months, beyond the allowed 14 day out of service time in technical specifications. Enforcement regarding this issue is provided in Section 4OA7 of this report. The LER is closed.

.6 (Closed) Licensee Event Report (LER) 50-251/2010-003-00, Damaged Speed Sensor caused the 4A Emergency Diesel Generator to be Inoperable

On May 10, 2010, during a normal surveillance test of 4A emergency diesel generator, frequency unexpectedly increased to approximately 63 Hz. Because of the erratic behavior, a normal shutdown was initiated and the 4A emergency diesel generator locked out due to piston cooling oil low pressure when the governor continued to be erratic. The licensee performed an investigation and determined the apparent cause of the 4A emergency diesel generator's uncontrolled speed/frequency and subsequent lock-out was a failure of the speed sensing magnetic pickup. The failure was due to the pickup being set too close to the engine flywheel during maintenance, even though it was within procedural acceptance criteria. Since the magnetic pickup was set during a maintenance activity, the 4A EDG was considered inoperable from the start of maintenance until the magnetic pickup was repaired. The licensee documented the event in the corrective action program as condition report 406620. Corrective actions included a change to the maintenance procedure to ensure that the run-out of the engine flywheel gear teeth was checked and the magnetic pickups were set with adequate clearance. The 4A EDG was inoperable for an approximate 16.9 days, beyond the 14 days allowed outage time in the technical specifications. The performance deficiency was characterized as a finding of very low safety significance (Green). Enforcement regarding this issue is provided in section 4OA7 of this report. The LER is closed.

4. OTHER ACTIVITIES

4OA5 Other Activities

.1 Inspector Review of INPO Report

a. Inspection Scope

The inspectors reviewed the interim report for the Institute of Nuclear Power Operations (INPO) evaluation of Turkey Point Nuclear Power Plant dated June 8, 2010. The onsite evaluation was completed in March 2010. The inspectors reviewed the report to ensure that issues identified were consistent with NRC perspectives of licensee performance and to verify if any significant safety issues were identified that required further NRC follow-up.

b. Findings

No findings were identified.

.2 On-Site Fabrication of Components and Construction of an ISFSI (60853, Revision 0)

a. Inspection Scope

The inspectors conducted a review of licensee and vendor activities in preparation for the concrete placement for the Independent Spent Fuel Storage Installation (ISFSI) pad upon which the Nuclear Horizontal Modular Storage (NUHOMS) horizontal storage modules (HSMs) will be sited to house spent fuel generated by the licensee. The inspectors walked down the construction area of the ISFSI pad and examined the rebar installation and verified that the rebar size, spacing, splice length, and concrete coverage on the top, side, and bottom complied to licensee-approved drawings, specifications, procedures, and other associated documents and that compliance to applicable codes, the Certificate of Compliance (CoC), and Technical Specifications (TSs) was met. The inspectors also evaluated the concrete formwork installation for depth, straightness, and horizontal bracing and verified the overall dimensions and orientation for compliance to the licensee-approved drawings. The inspectors also visited one of the two concrete batch plants contracted to supply the structural concrete to verify that it and the trucks to be used to transport the concrete to the site met code requirements. The inspectors interviewed licensee and contract personnel to verify knowledge of the planned work. The inspectors also observed the actual concrete placement and vibration of the ISFSI slab and observed tests for concrete slump and air content, temperature measurements, and the collection/preparation of cylinder samples for compression tests to verify that the work was implemented according to approved specifications and procedures. The inspectors later returned to the freshly poured pad to verify that the pad was being cured according to approved specifications and code requirements. Later, when the 7-day and 28-day compression tests were completed by the independent laboratory, the inspectors reviewed the results to verify that the acceptance criteria were met.

b. Findings

No findings were identified.

.3 Quarterly Resident Inspector Observations of Security Personnel and Activities

a. Inspection Scope

During the inspection period the inspectors conducted observations of security force personnel activities to ensure that the activities were consistent with the licensee security procedures and regulatory requirements relating to nuclear plant security. These observations took place during both normal and off-normal plant working hours.

These quarterly resident inspector observations of security force personnel and activities did not constitute any additional inspection samples. Rather, they were considered an integral part of the inspectors' normal plant status reviews and inspection activities.

b. Findings

No findings were identified.

4OA6 Meetings, Including Exit

Exit Meeting Summary

The resident inspectors presented the inspection results to Mr. Kiley and other members of licensee management on October 13, 2010. The inspectors asked the licensee whether any of the material examined during the inspection should be considered proprietary information. The licensee did not identify any proprietary information.

4OA7 Licensee Identified Violations

The following violations of very low safety significance (Green) were identified by the licensee and are violations of NRC requirements which meet the criteria of the NRC Enforcement Policy, NUREG-1600 for being dispositioned as NCVs:

- Technical Specification 3.8.1.1.b requires restoration of an inoperable diesel generator to operable status within 14 days or be in at least hot standby within the next 6 hours. Contrary to the above, during the period July 28, 2009 thru August 12, 2009, a period in excess of 14 days, the Unit 4 B emergency diesel generator was inoperable because of a faulty fuel strainer and Unit 4 was not placed in hot standby as required. When identified by the licensee during a surveillance test, the licensee entered the issue in the corrective action program as CR 2009-13740 and corrected the condition by replacing the entire fuel strainer assembly. A regional Senior Reactor Analyst performed a Phase III evaluation under the Significance Determination Process. The dominant internal events accident sequence was a single unit loss of offsite power followed by the common cause failure of all the emergency diesel generators with a failure to recover offsite power or an emergency

diesel generator before core damage two hours later. Assumptions of the evaluation included that common cause would be considered and, recovery of the failed diesel generator would not be considered. The exposure time for the evaluation was 14.3 days. Based upon this evaluation the performance deficiency was characterized as a finding of very low safety significance (Green). Further corrective actions to modify the strainer were planned.

- Technical Specification 3.8.1.1.b requires restoration of an inoperable diesel generator to operable status within 14 days or be in at least hot standby within the next 6 hours. Contrary to the above, during the approximate 1.5 month period prior to June 7, 2010, a period in excess of 14 days, the Unit 3 B emergency diesel generator was inoperable because of a failed fuel oil transfer pump and Unit 3 was not placed in hot standby as required. When identified by the licensee during a surveillance test, the licensee entered the issue in the corrective action program as AR 406564 and corrected the condition by replacing the failed transfer pump. This violation was of very low safety significance (Green) because alternate methods of filling the fuel oil day tank using available transfer pumps were proceduralized and available. Further corrective actions to develop a preventive maintenance activity to prevent similar failures were planned.

- Technical Specification 3.8.1.1.b requires restoration of an inoperable diesel generator to operable status within 14 days or be in at least hot standby within the next 6 hours. Contrary to the above, from April 27 through May 10, 2010, the unit 4A emergency diesel generator was inoperable approximately 16.9 days because of speed sensing magnetic pickup damage due to it being set too close to the engine flywheel during maintenance. When identified by the licensee during a surveillance test, the licensee entered the issue in the corrective action program as AR 406620 and corrected the condition. Additional corrective actions were implemented under the AR. A regional Senior Reactor Analyst performed a Phase III evaluation under the Significance Determination Process. The dominant internal events accident sequence was a single unit loss of offsite power followed by the common cause failure of all the emergency diesel generators with a failure to recover offsite power or an emergency diesel generator before core damage two hours later. Assumptions of the evaluation included that common cause would be considered and, recovery of the failed diesel generator would not be considered. The exposure time for the evaluation was 16.9 days. Based upon this evaluation the performance deficiency was characterized as a finding of very low safety significance (Green).

- 10 CFR Part 50, Appendix B, Criterion V, requires, in part, that activities affecting quality shall be prescribed by documented instructions or procedures of a type appropriate to the circumstances. The licensee implements this requirement, in part, with administrative procedure 0-ADM-503, Temporary System Alteration, which requires that a temporary system alteration design review be performed to ensure that the design of the alteration is consistent and compatible with the system and complies with the component design basis. Contrary to the above, from September 2 to 6, 2010, a temporary alteration was installed on the 3B and 4A vital batteries without a design review to assure the installation was consistent with the design

basis. When the unauthorized modification was identified to the licensee by a plant operator during rounds, the structures were removed and an evaluation initiated. The licensee determined that the batteries affected remained capable of their design function and this issue was documented into the corrective actions program as AR 577944. The finding was more than minor using NRC Manual Chapter 0612, Appendix E, Example 4.a because there were previous examples where the licensee failed to perform engineering evaluations for plant activities (NRC Inspection Reports. (05000251/2010-02-01, 05000250, 251/2009-003-05)

ATTACHMENT: SUPPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee personnel:
J. Alvarez, Performance Improvement Manager
B. Carberry, Emergency Preparedness Manager
C. Cashwell, Radiation Protection Manager
R. Coffey, Maintenance Manager
M. Crosby, Quality Manager
J. Garcia, Engineering Manager
G. Hollinger. Corporate ISFSI Manager
W. Jenkins, Site ISFSI Manager
M. Jones, Assistant Operations Manager
M. Kiley, Site Vice-President
J. Patterson, Fire Protection Supervisor
P. Rubin, Plant General Manager
B. Scott, Chemistry Manager
R. Tomonto, Licensing Manager
R. Wright, Operations Manager

NRC personnel:
D. Rich, Branch Chief, DRP

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened and Closed		
05000250,251/2010-004-01	NCV	Failure to provide adequate instructions when working on the reactor protection system results in reactor trip
Closed		
05000251/2009-001-00	LER	4B Emergency Diesel Generator Inoperable Due to Air-bound Main Fuel Pump
05000251/2010-001-00	LER	Two Shutdown Bank Rods Were Dropped from the Fully Withdrawn Position
05000250,251/2008-005-01	VIO	Failure to Accomplish an Activity Affecting Quality in Accordance With Procedures
05000250/2010-002-00	LER	Fuel Transfer Pump Failure Renders 3B Emergency Diesel Generator Inoperable
05000251/2010-003-00	LER	Damaged Speed Sensor caused the 4A Emergency Diesel Generator to be Inoperable

LIST OF DOCUMENTS REVIEWED

Section 4OA5.2: On-Site Fabrication of Components and Construction of an ISFSI (60853, Revision 0)

Procedures

St. Lucie Plant Mechanical Maintenance Procedure 0-MMP-116.14 ISFSI DSC Transport from CHF to HSM, Revision 6,

Specifications

Specification #5177-074-C112, Performance Specification for Placing Reinforcing Steel, Revision 1
Specification #5177-074-C351, Technical Specification for Purchase of Reinforcing Steel, Revision 3
Spec-C-085, Turkey Point ISFSI Construction Concrete Specification, Revision 3
Spec-C-086, Turkey Point ISFSI Construction Soil Improvement, Revision 3
Specification CN-2.11, Specification for Concrete Testing, Placing, Curing and Finishing

Plant Changes/Modifications (PCMs)

PC/M 06-011, ISFSI Haul Path
PC/M 06-012, Grading and Drainage for the ISFSI Project, Supplement 0, Revision 1,
PC/M 06-020, ISFSI Soil Improvement, Supplement 0, Revision 2
PC/M 06-021, ISFSI Pad and Apron, Supplement 0, Revision 1,

Change Request Notices (CRNs)

CRN #C-12666, For installation of geogrid soil reinforcement within soil improvement NITS portion of ISFSI embankment beneath the commercial revetment.
CRN #C-12677, Add water quality treatment pond and rerouted storm drainage piping to convey ISFSI runoff to water quality pond.
CRN #C-12685, To revise limit of soil improvement southeast of the storage building along and adjacent to the haul path.
CRN #C-12707, For installation of trench and associated concrete side walls and geogrid layers for protection of existing 13.8-kV line.
CRN #C-12780, Add water quality treatment pond and rerouted storm drainage piping to convey ISFSI runoff to water quality pond.

Drawings

PTN-C-06-020-001, ISFSI Project Existing Conditions Plan, Revision 0
PTN-C-06-020-002, ISFSI Project Site Preparation and Soil Improvement Plan, Revision 0
PTN-C-06-020-003, ISFSI Project Ground Improvement Sections and Details, Revision 0
PTN-C-06-020-004, ISFSI Project Sediment and Erosion Control Plan and Details, Revision 0
PTN-C-06-020-005, ISFSI Project Temporary Construction Plans, Revision 0
PTN-C-06-020-006, ISFSI Project Notes, Revision 0
PTN-C-06-020-007, ISFSI Project Soil Reinforcement Details, Revision 0
PTN-C-06-020-008, ISFSI Project Soil Improvements Dewatering Permit Plan, Sheets 1 through 4, Revision 4.
PTN-C-06-020-009, ISFSI Project Soil Improvements Primary Solid Disposal Area Plan, Sheets 1 through 3, Revision 0
5610-C-1962, ISFSI Soil Improvement Plan, Revision 0

Work Orders (WOs)

WO 39004649-04 (ER/PWO 92/7789), Excavate and Placement & Compaction of Limestone Fill in the Area of the ISFSI Pad.
Includes: Technique Sheet (TS) 10.4-1.2, Concrete Field Testing Revision 0
TS 10.4-2.2, Laboratory Testing of Concrete and Concrete Materials, Revision 0

WO 39004649-05 (ER/PWO 92/7789), QC Inspection and Documentation: Placement and Compaction of Limestone Fill in the Area of the ISFSI Pad.
Includes: In-Place Density Tests (ASTM D2922 and D1556)
Daily Log of Test Activities
Bulk Density Determination (ASTM D1556)
Particle Size Analysis of Soils (ASTM D422)

Other

Calculation Change Notice, Calc #FPL025-CALC-012, To verify that the capacity of the trench drains running parallel to the outside edge of the ISFSI apron proposed by the contractor meets the design parameters, Revision 1, dated 4 June
Storm Water Pollution Prevention Plan (SWP3)
Log of major excavation and grading activities (per page 29 of PC/M 06-012)
Contractor Daily Progress Reports (reviewed selected reports from October 27, 2009 through April 6, 2010)
Vendor Test Reports: Moisture-Density Curves per ASTM D1557 (selected reports from January to April 2010).
Grain Size Analysis (selected reports from October 2009 to March 2010).
Soil Testing Data/Records of ISFSI Project Soil Improvements (maintained by the ISFSI Civil Engineer), including: In-Place Density (per ASTM D2922 and D1556)
Special Inspector Log for ISFSI Soil Improvement Project
Drawings of ISFSI Project Soil Improvements Compaction Testing
Soil Improvement Test Maps
Design Requirements Document for the Basemat and Approach Slabs at Florida Power & Light Company's Independent Spent Fuel Storage Installation Sites
PTN ISFSI Compaction Data
ISFSI Pad Comprehensive Placement Plan
Material Test Reports for Rebar
Concrete Placement Records for ISFSI Pad
7-Day Compressive Test Results of Concrete Samples of ISFSI Pad
28-Day Compressive Test Results of Concrete Samples of ISFSI Pad

Section 1R07: Heat Sink Performance (HS) Activities

Procedures

3-OSP-019.4, Component Cooling Water Heat Exchanger Performance Monitoring, Revision 0
STD-ESI-92-002, Intake Cooling Water System Piping Inspections and Guidelines, Revision 2
3-OSP-030.9, Component Cooling Water System Flow Balance
3-OSP-030.4, Component Cooling Water Heat Exchanger Performance Test, Revision 0
0-PMM-030.01, CCW Heat Exchanger Cleaning and Inspection, Revision 0
Inspection of Dams and East Berm for Cooling Canal System

Condition Reports (CR)
CR 2006-1112, Degraded Rebars in Unit 3 ICW Valve Pit
CR 2007-26148, ASME XI Pressure Testing of Buried Piping
CR 2008-3893, Degraded Structure at Intake – Unit 3
CR 00573132, Exposed Rebar with Signs of Corrosion in the East, South, and West Walls of the Unit 3 Intake Cooling Water Valve Pit During the NRC Inspection
CR 00573209, Basis for CCW Heat Exchanger Maximum Tube Plug Criteria (Question by NRC Inspectors)

Others
Calculation PTN-BFSM-96-022, CCW Post Accident Heat-Up and Water Hammer
Calculation PTN-BFSM-90-060, RHR Heat Exchanger 3APerformance Test
Calculation PTN-BFSM-92-009, Component Cooling Water Heat Exchanger Plugged Tube Evaluation, Revisions 0 & 1
System Health Reports for Travel Screens and Screen Wash, 4/1-6/30/2010
PC/M No. 07-081, Containment Spray Pump Seal Water Modification
Work Order (WO) 37026021-01, Unit 4 Containment Spray Pump Seal Water Heat Exchanger 4P214A
WO 40012850-01, Component Cooling Water Heat Exchanger 3E207B
WO 39013296-03, Diving Inspection in Traveling Screen Bay
WO 39013296-01, Traveling Screen Inspection (36 months PM), 1/27/2010
Liquid Penetrant Reports for FW-5, 6, 8, 20, 21, & 23
Weld Examination Report FW-1 & FW-16 for Containment Spray Pump 4A Cooler and Associated Piping
Turkey Point East Side Canal Inspection (Inlet Canal and Outlet Canal), 5/1/2009
Canal Cooling System Grass-Weed Control Improvement Report 2008-2010
Turkey Point Daily Status Report – Canal System Weed Index
Grass/Algae Forecast Report
Chemical Component Test Sample Report
Unit 3 A, B, and C CCW Eddy Current Examination Final Results1/2008 – 7/2010
Turkey Point Unit 4B ICW Pipe Crawl Thru Final Inspection Report by PCA Engineering, 12/3/2009
Design Basis Document, Volume 12, Intake Cooling Water System
Testing on Procedure 4-OSP-019.01, Intake Cooling Water Inservice Test for 4P9B
Testing on Procedure 3 and 4-OSP-019.4, Component Cooling Water Heat Exchanger Performance Monitoring, 2/12/2010 & 2/12/2010
Testing on Procedure 3 and 4-OSP-030.4, Component Cooling Water Heat Exchanger Performance Test 6/228/2010 & 6/8/2010
Inspection on Procedure 0-PMM-011.01, Screen Wash Spray Nozzle Inspection for 4F1B, 1/27/2010
Performed on Procedure 3 & 4-OSP-030.9, Component Cooling Water System Flow Balance, 4/7/2009 & 12/13/2009