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

Report Nos.: 50-335/85-21 and 50-389/85-21

Licensee: Florida Power and Light Company
9250 West Flagler Street
Miami, FL 33102

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

Facility Name: St. Lucie 1 and 2

Inspection Conducted: August 13 - September 23, 1985

Inspectors: SAElrod 10/8/85
R. V. Crlenjak, Senior Resident Inspector Date Signed

SAElrod 10/8/85
H. E. Bibb, Resident Inspector Date Signed

Approved by: SAElrod 10/8/85
S. A. Elrod, Chief, Project Section 2C Date Signed
Division of Reactor Projects

SUMMARY

Scope: This routine, unannounced inspection entailed 190 inspector-hours on site in the areas of technical specification compliance, operator performance, overall plant operations, quality assurance practices, station and corporate management practices, corrective and preventive maintenance, site security procedures, radiation control activities, surveillance activities.

Results: Of the areas inspected, no violations or deviations were identified. One unresolved item was identified (para. 4).

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REPORT DETAILS

1. Persons Contacted

Licensee Employees

*K. Harris, St. Lucie Site Vice President
*D. A. Sager, Plant Manager
J. H. Barrow, Operations Superintendent
T. A. Dillard, Maintenance Superintendent
L. W. Pearce, Operations Supervisor
R. J. Frechette, Chemistry Supervisor
C. F. Leppla, I&C Supervisor
P. L. Fincher, Training Supervisor
C. A. Pell, Technical Staff Supervisor (Acting)
E. J. Wunderlich, Reactor Engineering Supervisor (Acting)
H. F. Buchanan, Health Physics Supervisor
G. Longhouser, Security Supervisor
J. Barrow, Fire Prevention Coordinator
J. Scarola, Assistant Plant Superintendent - Electrical
G. Wilson, Assistant Plant Superintendent - Mechanical
N. G. Roos, Quality Control Supervisor

Other licensee employees contacted included technicians, operators, mechanics, security force members, and office personnel.

*Attended exit interview

2. Exit Interview

The inspection scope and findings were summarized on September 25 and 27, 1985, with those persons indicated in paragraph 1 above.

The licensee did not identify as proprietary any of the materials provided to or reviewed by the inspectors during this inspection.

3. Licensee Action on Previous Enforcement Matters

This subject was not addressed in the inspection.

4. Unresolved Items

Unresolved items are matters about which more information is required to determine whether they are acceptable or may involve violations or deviations. Unresolved items are identified in paragraph 10.

5. Plant Tours (Units 1 and 2)

The inspectors conducted plant tours periodically during the inspection interval to verify that monitoring equipment was recording as required,

equipment was properly tagged, operations personnel were aware of plant conditions, and plant housekeeping efforts were adequate. The inspectors also determined that appropriate radiation controls were properly established, critical clean areas were being controlled in accordance with procedures, excess equipment or material was stored properly and combustible material and debris were disposed of expeditiously. During tours the inspectors looked for the existence of unusual fluid leaks, piping vibrations, pipe hanger and seismic restraint settings, various valve and breaker positions, equipment caution and danger tags, component positions, adequacy of fire fighting equipment, and instrument calibration dates. Some tours were conducted on backshifts.

The inspectors routinely conducted partial walkdowns of ECCS systems. Valve, breaker/switch lineups and equipment conditions are randomly verified both locally and in the control room. During the inspection period, the inspectors conducted a complete walkdown in the accessible areas of the Unit 1 Diesel Generators and Component Cooling Water to verify that the lineups were in accordance with licensee requirements for operability and that equipment material conditions were satisfactory.

6. Plant Operations Review (Units 1 and 2)

The inspectors periodically during the inspection interval reviewed shift logs and operations records, including data sheets, instrument traces, and records of equipment malfunctions. This review included control room logs and auxiliary logs, operating orders, standing orders, jumper logs and equipment tagout records. The inspectors routinely observed operator alertness and demeanor during plant tours. During routine operations, operator performance and response actions were observed and evaluated. The inspectors conducted random off-hours inspections during the reporting interval to assure that operations and security remained at an acceptable level. Shift turnovers were observed to verify that they were conducted in accordance with approved licensee procedures.

7. Technical Specification Compliance (Units 1 and 2)

During this reporting interval, the inspectors verified compliance with selected limiting conditions for operations (LCOs) and results of selected surveillance tests. These verifications were accomplished by direct observation of monitoring instrumentation, valve positions, switch positions, and review of completed logs and records. The licensee's compliance with selected LCO action statements were reviewed on selected occurrences as they happened.

8. Maintenance Observation

Station maintenance activities of selected safety-related systems and components were observed/reviewed to ascertain that they were conducted in accordance with requirements. The following items were considered during this review; limiting conditions for operations were met, activities were accomplished using approved procedures, functional testing and/or

calibrations were performed prior to returning components or systems to service; quality control records were maintained; activities were accomplished by qualified personnel; parts and materials used were properly certified; and radiological controls were implemented as required. Work requests were reviewed to determine status of outstanding jobs and to assure that priority is assigned to safety-related equipment.

9. Review of Nonroutine Events Reported by the Licensee (Units 1 and 2)

The following licensee event reports (LERs) were reviewed for potential generic impact, to detect trends, and to determine whether corrective actions appeared appropriate. Events which were reported immediately were also reviewed as they occurred to determine that technical specifications were being met and that the public health and safety were of upmost consideration. The following LERs are considered closed:

Unit 1: 335/85-07, 335/83-24

Unit 2: 389/85-07*

*In-depth review performed

On August 21, 1985, Exxon Nuclear Company, Inc. (ENC) notified Florida Power & Light Company of a nonconservative error in an input value for the St. Lucie unit 1 cycle six fuel, loss of coolant accident - emergency core cooling system (LOCA-ECCS) analysis. The input error consists of using an incorrect value for the reactor coolant pump torque. The torque used was 11,011 ft-lbf rather than the correct torque of 32,495 ft-lbf.

ENC was performing LOCA-ECCS calculations for St. Lucie Unit 1 which have incorporated input based on measured plant data and assumes increased levels of steam generator tube plugging. It was during this effort that the error in primary pump input was identified. The pump model input has been corrected for these calculations and preliminary results can be used to estimate the effort of the pump model change. The limiting break which had been identified in the previous analysis for the licensing basis, has been recalculated and gives a calculated peak cladding temperature (PCT) of 2194°F at the current linear heat generation rate (LHGR) Technical Specification limit of 15.0 kw/ft and the maximum stored energy point of 2.4 MWD/kg peak rod average burnup, and a tube plugging of 15 percent per steam generator. The PCT dropped to 2042°F at the same LHGR and a peak rod average exposure of 15.0 MWD/kg.

Calculations indicate that the corrections to the pump torque input error in the St. Lucie Unit 1 analysis may affect what size LOCA break is limiting. Results indicated that a larger break may become limiting, and that the PCT for this break may exceed that for the previously limiting break by up to 250°F. Thus, to assure compliance to 10 CFR 50.46 criteria, a reduction in the allowed LHGR limit sufficient to reduce PCT to below 2200°F is needed. A conservative estimate in the sensitivity of PCT to known reductions in LHGR was obtained by performing a heatup calculation for St. Lucie Unit 1

with an input reduction in LHGR of 0.1 kw/ft from 15 kw/ft. This calculation gave a PCT reduction of 15.7°F.

Based on this sensitivity of 15.7°F/0.1 kw/ft, an LHGR reduction from the current limit of 15 kw/ft was calculated as a function of burnup. A limit of 14.0 kw/ft would conservatively satisfy the 10 CFR 50.46 criteria from this point in Cycle Six until the next refueling outage.

A brief review indicated that St. Lucie Unit 1 never operated above a LHGR of 14.0 kw/ft during Cycle Six. During normal full power operation, the measured LHGR is approximately 12.5 kw/ft (including uncertainties). The highest expected LHGR during Cycle Six would have been during moderator temperature coefficient testing. During that test, the highest LHGR measured was 13.42 kw/ft. Thus, the conservative margin between the design conditions and the less severe normal operating conditions probably prevented exceeding the 14.0 kw/ft limit.

On Sept. 4, 1985 the NRC RII issued a Confirmation of Action letter which concurred with the FPL commitment (ref. FPL L-85-331) to administratively restrict the LHGR to 14.0 kw/ft for the remainder of cycle 6 for St. Lucie Plant, Unit 1 (ref. CAL 50-335/85-01).

On August 8, 1985, the St. Lucie Unit 2 reactor was operating at normal full power. At 2:02 a.m., a fuse blew in the A train electrical supply to the engineered safeguards actuation cabinet relays. This resulted in both main steam isolation valves (MSIV) closing and a reactor trip. Additionally, a containment isolation actuation signal resulted in a loss of component cooling water (CCW) to all reactor coolant pumps (RCPs). The licensee elected to replace all from RCP seals due to the loss of CCW (ref. IE Report Nos. 50-335/85-20 and 50-389/85-20 and PNO-II-85-76).

The RCP seal replacement was completed on August 12, 1985. Reactor coolant system (RCS) pressurization was commenced on August 13, 1985. On August 14, 1985, with system temperature and pressure at 520°F and 1600 psia respectively, the 2B1 RCP seal failed. On August 16, 1985, with 2B1 RCP seal replacement complete, RCS fill and vent was commenced. On August 17, 1985, with system temperature and pressure at 465°F and 1600 psia, respectively, the 2A1 seal failed. On August 19, 1985, after completing seal replacement RCS fill and vent was commenced. Several hours later with system pressure at 400 psia the 2A1 RCP seal failed again. On August 21, 1985, after completing seal replacement, RCS fill and vent was commenced. A reactor startup was commenced on August 22, 1985. This concluded the series of failures to the Unit 2 RCP primary seals. With the exception of the initial four seal failures, the problems experienced with the subsequent seals were apparently not related.

On August 22, 1985, a new series of problems began to affect the Unit 2 RCPs. However, these problems were associated with the prime mover or motor end vice the pump end. The problems were vibration related and were most severe or the 2A2 RCP.

On August 24, Unit 2 was in Mode 3 pending resolution of the vibration problem on the 2A2 RCP. Vibration readings of approximately 20 mills were indicated on the Bently-Nevada (B/N) instrumentation for the lower motor shaft. At 0239, the pump was restarted following an inspection of the pump coupling bolts. At 0259, an ionization detector in the area of the 2A2 RCP alarmed. A nuclear operator (NO), already in containment, was contacted by the control room operator and sent to investigate. A few minutes later the 2A2 RCP was secured when the NO reported leaking oil and smoke in the vicinity of the pump. Subsequent investigation determined that approximately six gallons of oil (Texaco RNO-68) had leaked from the lower oil reservoir.

At 0325, the oil which was in contact with the hot reactor coolant system (RCS) piping caught fire. The on-site fire brigade was called and the fire extinguished without outside assistance (ref PNO-II-85-76). A cooldown from 532°F to 400°F was initiated to prevent the remaining oil from flashing (flash point, 450°F). The unit was subsequently placed in mode 5 and the pump motor was disassembled and inspected.

The four RCPs installed in Unit 2 consist of Allis-Chalmers 6500 H. P., 6.9 Kv motors coupled to Byron-Jackson type DFSS vertical, single stage, pumps. The lower motor oil reservoir contains the lower radial guide bearing and a Kingsbury type thrust bearing. The reservoir is normally filed with 130 gallons of oil and is the suction supply for the oil lift pumps. Disassembly of the motor revealed a damaged oil slinger ring and a failed oil seal.

The aluminum oil slinger ring, located above the thrust housing, consists of separate rotating and stationary components and is designed to prevent oil from being lost through the top of the reservoir. The rotating portion consists of two semi-circular halves which are bolted together around the thrust collar at a point located above the normal oil level. This rotating part is mated to the thrust collar by an interference fit and rotates with the collar. The stationary part is a ring which is attached to the underside of the top of the reservoir. The raised outer edge of the rotating ring moves in a matching groove in the stationary ring. the two pieces which made up the assembly are not designed to make contact. During disassembly the rotating ring was found fused to the stationary ring and the inside diameter of the rotating ring was badly damaged where the thrust collar had rotated underneath it. The collar was found embedded with aluminum and blued due to the heat generated by this rotation.

The inside radial wall of the oil reservoir is formed by a oil retaining sleeve, commonly referred to as a "stovepipe", which is positioned radially between the motor shaft and the inside diameter of the thrust collar. The stovepipe is bolted to the bottom of the reservoir and is sealed by an O-ring. Two oil seal rings are interference fitted, one above the other, to the top of the stovepipe. The aluminum oil seal rings are of a labyrinth design and do not normally make contact with the rotating thrust collar. The lower seal is normally bathed in oil while the upper seal is dry. Oil which may be present in cavity between the seals due to centrifugal force

exerted by the rotating collar is prevented from running up the stovepipe, over the underside of the collar, and down the shaft by a pair of vent holes drilled through the collar. Oil flowing through the vent holes is returned to the reservoir. The upper oil seal was found to be broken free of the stovepipe, axially expanded, and partially split.

It is believed that vibration of the motor shaft caused the rotating ring to rub against its stationary counterpart. The friction and heat generated eventually caused the ring to break free of the thrust collar. The thrust collar then began to rotate independently of the oil ring generating more heat, by friction, at the interface of these two parts. Much of the heat was absorbed by the thrust collar. The collar expanded and began to loosen slightly on the shaft, which may have further increased the pump vibration. The upper seal came in contact with the collar and began to rub due to the combination of vibration and heat radiated from the thrust collar. Subsequently the upper oil seal broke free and began to rotate with the thrust collar as the outside edge of the oil seal wore away and the surface area for contact increased due to the cut of the grooves. The heat from the rubbing oil ring was conducted through the collar and caused the seal to expand axially. The seal eventually deformed and partially split at one point such that it began to act as a screw pump, pumping the oil from the intra-seal cavity out and down the shaft. The oil was then sprayed into the general area. Some oil worked underneath the insulation surrounding the pump casing and associated piping, subsequently beginning to smoke and ignite.

The initial corrective actions were to repair the damage, balance the pump and motor, and return the Unit to service. Repairs and balancing of the 2A2 RCP was completed on September 6 and the unit was returned to service on September 7. On September 9, a review of plant logs by operating personnel detected an upward trend in the 2A2 RCP vibration readings. At 1912 a 2A2 RCP vibration alarm was received with increasing bearing temperatures. Because plant technical specifications require all four RCPs for Critical operations the Unit 2 reactor was manually tripped at 1920.

Disassembly of the 2A2 RCP again revealed similar damage. However, no oil had leaked during this failure. A team of experts form Florida Power and Light Co. (FPL) and the appropriate vendors was formed to investigate the causes of the past events and examine the necessary corrective actions. Modifications were recommended and made to the oil ring and seals. The raised lip of the slinger ring was machined to provide greater clearance and the interference fit of the ring on the thrust collar was increased. Clearance on the oil seal was also increased, the seal glooves were remachined to limit the increase in surface area should the seal rub in the future, and the seal was attached to the stovepipe with set-screws. The pump was balanced and tested and the unit returned to service on September 21 at 2107.

10. In addition to the reactor coolant pump problems described in paragraph 9, on September 1, 1985, another problem with the 2A2 Reactor Coolant Pump (RCP) was identified. Several of the anti-reverse rotation ratchet devices

were found to be lodged in their holes in the RCP flywheel. The bottom, or tips of the pins were mushroomed such that, as the pins retracted into their respective holes, some lodged and became ineffective. There are 36 pins per RCP flywheel and the Unit 2 Final Safety Analysis Report states that only one pin is required to prohibit reverse rotation during accident conditions. The remaining Unit 2 RCPs were inspected and similar problems were identified. All Unit 2 RCP anti-rotation pins were replaced. The RCPs were again inspected after the September 10 shutdown. Mushrooming of the pins was again noted. FPL engineering elected to taper all Unit 2 pins at the bottom so any minor mushrooming would not result in the pins stitcking in the retracted position. Additionally, the pins were sampled to determine if they were fabricated of the proper materials. This inspection determined that the pins in use on the Unit 2 pumps were fabricated or materials of inadequate tensile strengths. Because only 72 pins of the required strength were available and 144 were needed, the plant elected to replace every other pin in all Unit 2 RCPs prior to unit start up. Unit 1 anti-rotation pins have been inspected on several occasions over its operating life with no problems being identified. It appears that only Unit 2 of the two units at St. Lucie had the defective pins installed. Because the reportability of this item is in question it is considered unresolved, Anti-rotation pins reportability (50-389/85-21-01).

11. Physical Protection (Units 1 and 2)

The inspectors verified by observation and interviews during the reporting interval that measures taken to assure the physical protection of the facility met current requirements. Areas inspected included the organization of the security force, the establishment and maintenance of gates, doors and isolation zones in the proper conditions, that access control and badging was proper, and procedures were followed.

12. Surveillance Observations

During the inspection period, the inspectors verified plant operations in compliance with selected technical specifications (TS) requirements. Typical of these were confirmation of compliance with the TS for reactor coolant chemistry, refueling water tank, containment pressure, control room ventilation and AC and DC electrical sources. The inspectors verified that testing was performed in accordance with adequate procedures, test instrumentation was calibrated, limiting conditions for operation were met, removal and restoration of the affected components were accomplished, test results met requirements and were reviewed by personnel other than the individual directing the test, and that any deficiencies identified during the testing were properly reviewed and resolved by appropriate management personnel.