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

Report Nos.: 50-335/92-05 and 50-389/92-05

Licensee: Florida Power & Light Co
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: February 25 - March 23, 1992

Inspectors:	for S. A. Elrod, Senior Resident Inspector, St. Lucie Site	4/16/92 Date Signed
	M. A. Scott, Resident Inspector	4/16/92 Date Signed
	for R. C. Butcher, Senior Resident Inspector, Turkey Point Site	4/16/92 Date Signed
	for M. Lesser, Senior Resident Inspector, North Anna Site	4/16/92 Date Signed
	R. P. Schin, Project Engineer	4/16/92 Date Signed
Approved by:	K. D. Landis, Section Chief, Division of Reactor Projects	4/22/92 Date Signed

SUMMARY

Scope:

This routine resident inspection was conducted onsite in the areas of plant operations review, maintenance observations, surveillance observations, fire protection review, review of nonroutine events, followup of regional office requests, and followup of previous inspection findings.

Results:

This inspection found that the licensee operated the two units in a routine manner with obvious regard for safety. Minor events occurring during the period, such as a loss of circulating water pump and an emergency diesel generator failure during testing, received prompt responses consistent with the

event. Maintenance controls were appropriate for the various maintenance activities. Followup inspection to Service Water Inspection 335,389/91-201 produced enforcement findings which were issued with this report.

Within the areas inspected, the following violations were identified:

VIO 335,389/92-05-04, Inadequate Test of Intake Cooling Water Pump, paragraph 7d.

VIO 335/92-05-05, Failure to Test Certain Valves Quarterly as Required by the Inservice Test Program, paragraph 7e.

Within the areas inspected, the following unresolved item was identified:

URI 335,389/92-05-06, Evaluation of whether or not Air Controls for Component Cooling Water Temperature Control Valves should be Safety Related, paragraph 9e.

Within the areas inspected, the following non-cited violation was identified:

NCV 335,389/92-05-03, Inadequate Training Materials, paragraph 7c.

Within the areas inspected, the following non-cited deviation was identified:

NCD 335,389/92-05-02, Failure to Maintain Submersible Valve Qualifications as Described in the Final Safety Analysis Report, paragraph 7b.

REPORT DETAILS

1. Persons Contacted

Licensee Employees

D. Sager, St. Lucie Plant Vice President
* G. Boissy, Plant General Manager
J. Barrow, Fire/Safety Coordinator
H. Buchanan, Health Physics Supervisor
* C. Burton, Operations Manager
R. Church, Independent Safety Engineering Group Chairman
* R. Dawson, Maintenance Manager
* R. Englmeier, Nuclear Assurance Manager
R. Frechette, Chemistry Supervisor
* J. Holt, Plant Licensing Engineer
C. Leppla, Instrument and Control Supervisor
* L. McLaughlin, Licensing Manager
G. Madden, Plant Licensing Engineer
A. Menocal, Mechanical Supervisor
* T. Roberts, Site Engineering Manager
L. Rogers, Electrical Supervisor
N. Roos, Services Manager
C. Scott, Outage Manager
* M. Shepherd, Operations Training Supervisor
D. West, Technical Manager
J. West, Operations Supervisor
W. White, Security Supervisor
D. Wolf, Site Engineering Supervisor
E. Wunderlich, Reactor Engineering Supervisor

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

NRC Employees

* S. Elrod, Senior Resident Inspector, St. Lucie Site
* M. Scott, Resident Inspector, St. Lucie Site
M. Lesser, Senior Resident Inspector, North Anna Site
R. Butcher, Senior Resident Inspector, Turkey Point Site
* R. Schin, Project Engineer, Division of Reactor Projects

* Attended exit interview

Acronyms and initialisms used throughout this report are listed in the last paragraph.

2. Review of Plant Operations (71707)

Unit 1 and Unit 2 began and ended the inspection period at power - days 91 and 473 of continuous power operation, respectively.

During the inspection period, a number of INPO personnel were onsite for two weeks conducting evaluation activities.

During the inspection period, both the cognizant NRC Region II Project Branch Chief and the Deputy Director of the NRC Region II Reactor Projects Division visited the site.

a. Plant Tours

The inspectors periodically conducted plant tours 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 materials 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 frequency of plant tours and control room visits by site management was noted to be adequate.

The inspectors routinely conducted partial walkdowns of ESF, ECCS, and support systems. Valve, breaker, and switch lineups as well as equipment conditions were randomly verified both locally and in the control room. The following accessible-area ESF system and area walkdowns were made to verify that system lineups were in accordance with licensee requirements for operability and equipment material conditions were satisfactory:

Unit 2 EDGs,
Unit 1 and 2 SFPs,
Unit 1 and 2 SFP pumps and heat exchangers, and
Unit 2 Control Room ventilation.

On March 9, 1992, while touring the Unit 1 B-train 4160 Volt switchgear room, the inspector observed that the 1B ICW breaker had been removed from its switchgear housing and was sitting unrestrained in front of other safety-related switchgear. Based on nuclear industry concerns regarding seismic qualification of safety-related switchgear with breakers in racked-out or removed condition, the licensee was informed that the removed breaker should be restrained to prevent possible safety-related switchgear damage during a seismic event. The licensee initiated REA 92-104, requesting engineering evaluation of circuit breaker seismic loading/qualification in various positions other than fully installed. This issue will be tracked as IFI 50-335,389/92-05-01, Seismic Qualification of Racked Out Circuit Breakers.

At 9:30 p.m. on March 14, Unit 2 control room operators recognized a loss of RTGB annunciator panels H, J, K, L, M, and N due to lit annunciators becoming very dim and no annunciator lights on these panels lighting brightly when checked. Operators entered ONOP 2-0030137, Partial or Complete Loss of Annunciators, Rev. 1. The ONOP was written in the two column EOP format and did contain guidance for operators; including checking all alarm panels for the extent of the malfunction, referring to an Annunciator Summary procedure to assess the impact of the lost annunciators, increased monitoring of the RTGB, and implementing the Emergency Plan per EPIP 3100022E, Classification of Emergencies. The EPIP required declaration of an Unusual Event based on a loss of indication or alarm panels which, in the opinion of the NPS/EC, would significantly impair accident or emergency assessment. An unusual event was not declared. (The inspector later reviewed the approximately 240 annunciators lost with an NPS who described why he also would not have declared an Unusual Event.) The ONOP also directed operators to check annunciator power supplies and contact the I&C staff. At 10:48 p.m., I&C personnel manually bypassed the power supply inverter (and its logic) and restored the annunciator panels to operation on backup 120 volt ac power. I&C personnel subsequently replaced the failed annunciator power supply inverter and logic assembly.

Shop testing of the failed power supply assembly revealed a previously unseen failure mode. A 12 volt regulator had failed, causing 28 volt unregulated dc voltage to be introduced into the 12 volt regulated dc voltage sensor card. The voltage sensor card failed, causing the two power supply switching relays to chatter as they switched back and forth between the normal (120 volt ac through the power supply assembly) and alternate (125 volt dc through the inverter) power sources. This caused the related alarm lights in the control room to become very dim. I&C determined that a similar failure to a different power supply assembly could cause the loss of virtually all control room annunciators. For long term corrective action, I&C initiated an REA requesting modification of the annunciator power supply to limit such a failure to a specific group of annunciators. Also, the licensee labeled the power supply inverter bypass switches (located inside cabinets in the cable spreading room) and issued a temporary change to ONOP 2-0030137 on March 19. This temporary change gave operators instructions on when and where to operate the power supply inverter bypass switches. The inspector walked down the temporary change with an operator and found that the bypass switches were clearly labeled, but were located inside different cabinets than those listed in the temporary change. The inspector gave this information to the NPS on shift for correction of the temporary change.

On March 15, the 2B1 circulating water pump failed. Prior to the failure, the pump had been restarted at 9:05 a.m. following the 2B1 main condenser water box post-cleaning return to service. Subsequent power ascension was stopped at 90 percent for turbine valve testing at 10:20 a.m. At 1:15 p.m. operations noticed the main turbine generator megawatt output decreasing and main condenser back pressure increasing. Approximately two minutes later, the operators noticed the 2B1 circulating pump current reduced from the normal 220 to 270 ampere range to 130 amperes. The control room operators began a downpower and dispatched other operators to observe the pump.

The non-licensed turbine operator and an SRO found that the 2B1 pump had an overheated shaft and gland area. The area was visibly warm. The pump was shut down at approximately 1:20 p.m. Plant power was stabilized at 85 percent at this time.

At 1:40 p.m. on the same day, a non-licensed operator observed that the 2A MFP had lost some amount of lubricating oil. The reservoir was down about 5 gallons when checked, and oil was visible around and dripping from the coupled pump bearing. Oil was added to the reservoir, the mechanical maintenance staff was called, and the predictive maintenance staff was called for an oil sample.

As a conservative measure, at 2:10 p.m., plant power was further reduced to approximately 70 percent in case there was a problem with the MFP. The plant could not be maintained on line at this power should a MFP trip because the MFPs were only 60 percent capacity pumps, however power was not reduced below 70 percent due to shutdown margin restraints and the 4 hour LCO time restraints of TS 3.1.3.6, Regulating CEA Insertion Limits. If the MFP had tripped from 70 percent power, the operators planned to quickly reduce power to keep the plant on line and temporarily enter the TS 4 hour LCO.

Subsequent 2A MFP observation, evaluation, and oil sample laboratory results revealed no probable pump problems. No upward trending bearing temperatures were observed. Vibration analysis indicated no changes in pump vibration. Oil sample analysis indicated no oil degradation. The initial conclusion drawn was that pump had experienced some minor, unexplained transient. Further analysis would follow. At 9:30 p.m., after the laboratory results were digested, power was increased to around 90 percent, the maximum achievable with the missing 2B1 circulating pump and resulting condenser back pressure limitations.

The circulating pump was carefully disassembled to understand its failure mode. The shaft had cracked or cracked and rewelded itself. The shaft sleeve on which the packing rode had been heated to the point that portions of it had been welded to the packing gland. The affected parts were removed to the licensee's materials laboratory for further evaluation. At the time of discovery, the licensee thought that sufficient water lubrication and cooling was available to the pump packing area based on feedback from the non-licensed operator who had started the pump at 9:05 a.m. The licensee is continuing their review and root cause determination.

b. Plant Operations Review

The inspectors periodically 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. They observed and evaluated control room staffing, control room access, and operator performance during routine operations. The inspectors conducted random off-hours inspections to assure that operations and security performance remained at acceptable levels. Shift turnovers were observed to verify that they were conducted in accordance with approved licensee procedures. Control room annunciator status was verified. Except as noted below, no deficiencies were observed.

During this inspection period, the inspectors reviewed tagout (clearance) 2-2-86 - 2B EDG for PMs.

Due to a need to reduce condenser tube fouling rates and reduce the overall environmental effluents, the licensee has obtained an EPA permit for use of a chemical agent to reduce clam growth in the plants' intake structures and condensers. The chemical agent would be an adjunct to the existing use of hypochlorite. Hypochlorite has had a minimal effect on the clams, oysters, and bivalves for which the chemical agent was targeted. On March 4, 1992, a contractor began injection of the chemical agent into the Unit 1 intake structures. The injection period lasted approximately 10 days. The trial period will be 18 months in duration with injections occurring every 2 to 3 months.

The posting of required notices to workers was reviewed and was noted to be satisfactory.

c. Technical Specification Compliance

Licensee compliance with selected TS LCOs was verified. This included the review of selected surveillance test results. These verifications were accomplished by direct observation of monitoring instrumentation, valve positions, and switch positions, and by review of completed logs and records. Instrumentation and recorder traces were observed for abnormalities. The licensee's compliance with LCO action statements was reviewed on selected occurrences as they happened. The inspectors verified that related plant procedures in use were adequate, complete, and included the most recent revisions.

Because during the inspection period, the 2B EDG had been placed out of service for PMs and subsequently returned to service, the 2A EDG was started on February 27 for an idle start operational check per TS 3.8.1.1.b. The 2A EDG's 2A1 (16 cylinder) engine established the required fuel rack position for 450 rpm on the idle start test while the 2A2 (12 cylinder) engine accelerated to 900 rpm, carrying the 16 cylinder engine to the same speed - the engines were coupled via the common generator between them. Appropriate annunciation lit.

The speed adjusting Bodine brand motor on the 2A2 engine's governor was found missing a brush. This left the motor inoperative and locked in its last operating position, which had been at its high speed stop. Due to the Bodine motor problem, the governor was at its high fuel rack stop (which would produce 900 rpm). This position was fortuitous in that, had the 2A EDG received an emergency start signal, the generator would have loaded with required emergency bus loads.

The screwed-on brush cap that held the brush spring and brush against the motor commutator had loosened. The brush and cap were found atop the governor housing just beneath the motor. Speculation was that the externally threaded cap had loosened because of diesel running vibration. Work instructions were issued and implemented that evening (February 24) to check tight all Bodine motor brush caps.

Due to loss of governor control, the 2A EDG was declared inoperable. The 2B EDG was started on February 28 within 24 hours, per TS 3.8.1.1.b. A special report is due from the licensee within 30 days.

By the end of the inspection period, the licensee had obtained a telecon from the governor vendor for a fix on the Bodine motors. The vendor indicated that currently the motors were being sold with a dot of RTV in the brush-cap-to-motor-body joint to inhibit vibration induced loosing of the brush cap. At the end of the inspection, the licensee had received on-site review committee approval for repair instructions to apply a dab of RTV to the exterior of the screwed joint. The remaining brush caps were subsequently verified to be tight. The resident inspectors were collecting information regarding the specific event for consideration as a generic issue.

d. Physical Protection

The inspectors verified by observation during routine activities that security program plans were being implemented as evidenced by: proper display of picture badges; searching of packages and personnel at the plant entrance; and vital area portals being locked and alarmed.

Observed operator deportment and actions during the recovery phase of the Unit 2 2B1 circulating water pump loss were commendable. Followup actions on the transient experienced by the 2A MFP were thorough. Staff actions were timely in their support of plant operations.

3. Surveillance Observations (61726)

Various plant operations were verified to comply with selected TS requirements. Typical of these were confirmation of TS compliance for reactor coolant chemistry, RWT conditions, 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, LCOs were met, removal and restoration of the affected components were accomplished properly, 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. The following surveillance tests were observed:

a. OP 2-2200050, Rev 38, Emergency Diesel Generator Periodic Test and General Operating Instructions, 2B EDG

b. OP 2-2200050, Rev 38, Emergency Diesel Generator Periodic Test and General Operating Instructions, 2A EDG. The 2A EDG test is discussed in paragraph 2.c of this report.

c. OP 1-2200050, Rev 61, Emergency Diesel Generator Periodic Test and General Operating Instructions, 1A EDG

d. OP 1-0700050, Rev 37, Auxiliary Feedwater Periodic Test, 1A pump

e. OP 2-0030150, Rev 33, Secondary Plant Operating Checks and Tests, Section 8.1.4, Turbine Valves. During the turbine governor valve tests on February 24, paragraph 8.1.4.k (OP 2-0030150), the indicating lights on the control board did not react as predicted. The DEH "open" light did not extinguish when three of the four governor valves went closed (on the fourth valve, the light went out).

   I&C personnel indicated that the "open" light was operated by the snap-lock valve position switches. Often during long runs between operation of the valve position switches, the switches have frozen due to corrosion buildup. This was described as an industry-wide phenomenon. I&C had an operations-written NPWO to repair the affected switches. Additionally, I&C had been working with vendors toward potentially replacing the snap-lock switches with magnetic/reed switches. A REA was to be submitted to site engineering on the subject.

   Not addressed by the procedure were the alternate methods actually used by operations to verify valve closure. An SRO and a non-licensed operator were at the valves when they were cycled to observe proper operation. Valve test lights on the vertical DEH control board changed state. Also, the digital readout ceased downward trending at 0.6 to 2.0 percent closed (this indicated closed but due to cold calibration of the valve position indication absolute zero indication did not occur with the valve hot). A change to this procedure was instituted to add the alternate means of verifying valve closure.

f. OP 1-0700050, Rev 37, Auxiliary Feedwater Periodic Test, 1B pump. During the surveillance of the 1B AFW pump, it was observed that one of the motor's louvered exit covers was installed with the louvers opening upward. Since there was no rain catch or lip above this cover, this would tend to invite rain water entry when the pump was not operating. Subsequent review showed that, due to construction of the motor housing, water would only enter the shielding shroud and still would not gain direct entry to the motor windings or bearings. Standing water in the internal shroud volume would tend to induce rust degradation of the shroud. The louver installation was subsequently corrected.

The surveillances for this period were fully acceptable with the exception of the 2A EDG.

4. Maintenance Observation (62703)

Station maintenance activities involving 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: LCOs were met; activities were accomplished using approved procedures; functional tests 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 the status of outstanding jobs and to assure that priority was assigned to safety-related equipment. Portions of the following maintenance activities were observed:

a. NPWO 7162/63 RPS "C" subchannel Low Level S/G Failed Surveillance 1-1400050

b. NPWO 7185/64 Unit 2 Annunciator Power Supply Logic Housing Failure

c. NPWO 4733/61 Repack Charging Pump 1C

d. NPWO 4633/66 4160 V Switchgear 2B3 (SB) Feeder to Bus 2AB. Per NPWO instructions, the feeder breaker from the "B" side safety 4160 Volt switchgear was removed and replaced in a routine manner. The removed breaker would be overhauled by a vendor as had the breaker that replaced it. A spare breaker was overhauled and readied for this pre-outage activity. The effort was part of attempt to complete the Unit 2 4160 Volt breaker nine-year overhaul cycle. The feeder breaker was not carrying any load at the time of the transfer. Operations personnel who racked the breakers out and in utilized procedure OP 2-0910023, Rev 5, Transfer Electrical Alignment on the

4160V and 480V Load Center 2AB Buses. The replacement breaker tested satisfactorily.

e. NPWO 4610/61 Dragon Valves Model Numbers 10615 and 10905, Inspect for Loose Packing Nuts

f. NPWO 2729/62 Dragon Valves in ECCS Rooms

NPWOs e. and f. above, for Dragon valves, were followed this report period due to an event found during the last report period and discussed in report 335,389/92-04. Several of the safety-related vent and drain valves in the Unit 1 ECCS room were found with their packing retaining nuts less than hand tight. Based on tightening instructions provided by the vendor, these NPWOs direct checking the tightness of the nuts in both units.

The observed maintenance activities were satisfactory and controlled appropriately.

5. Fire Protection Review (64704)

During the course of their normal tours, the inspectors routinely examined facets of the Fire Protection Program. Normally the inspectors reviewed transient fire loads, flammable materials storage, housekeeping, control of hazardous chemicals, ignition source/fire risk reduction efforts, fire protection system surveillance program, fire barriers, and fire brigade qualifications.

The fire protection program seemed to be working well during this period.

6. Onsite Followup of Events (Units 1 and 2)(93702)

Nonroutine plant events were reviewed to determine the need for further or continued NRC response, to determine whether corrective actions appeared appropriate, and to determine that TS were being met and that the public health and safety received primary consideration. Potential generic impact and trend detection were also considered.

The events discussed in paragraph 2 (annunciator problems, circulator pump failure, and EDG failure) were handled promptly with active management overview.

7. Followup of Inspector Identified Items (Units 1 and 2) (92701)

a. (Closed - Units 1 and 2) URI 335,389/91-201-01, Pre-operational Test Review.

This URI identified several ICW system pre-operational test anomalies. The licensee reviewed the following discrepancies to ensure that system capabilities were known:

(1) Inconsistences were found in flow and differential pressure data at different points in the test although the system alignment was apparently the same.

The licensee attributed this to modulation of temperature control valves during the test which may have changed the system parameters. Since the intent of this portion of the test was to obtain system flow characteristic data for modeling purposes, the parameter changes were found not to be significant. The inspector had no further questions on this point.

(2) Minimum acceptable flow was not maintained at all times during the test.

The licensee evaluated this and determined that the intent of the stated minimum flow was to approximate expected flow rates and that operation below this value did not affect the test. The inspector had no further questions on this point.

(3) The pre-operational test did not establish travel stops on flow control valves to prevent pump runout.

The licensee determined that travel stops were used at some point during the pre-operational testing phase and not documented as such. The licensee could not determine exactly when and why they were used other than to address the concern with pump runout which apparently developed during the testing. The licensee recently implemented modifications that control runout flow by use of orifices and negated the requirements for FCV travel stops. The inspector had no further questions on this point.

(4) Valve settings for the backup source of lubrication water to the ICW pumps were not established.

The licensee referenced FSAR section 9.2.1 which stated that the backup source of lubrication (domestic water system) was only required during initial ICW pump startup [when the ICW system would be empty] and was not needed for restart of a pump following loss of offsite power. The licensee determined that valve settings for the domestic water system were not required. The inspector had no further questions on this point.

(5) There were significant differences in differential pressures recorded for ICW strainers.

The licensee attributed differences to strainer cleanliness or gauge reading inaccuracies and concluded that the differences did not affect the test results. The inspector had no further questions on this point.

The inspector concluded that the licensee adequately reviewed the anomalies and that they did not significantly affect the outcome of the pre-operational test.

b. (Closed - Units 1 and 2) Deficiency Item 335,389/91-201-01, Incomplete and Inaccurate FSAR Discussions.

The inspector reviewed the following discrepancies regarding FSAR discussions of the ICW system:

(1) Valves MV-21-2 and MV-21-3 were described in the FSAR as having been upgraded (Unit 1) or qualified (Unit 2) for submersible service yet were subsequently determined during inspection 91-201 not to be qualified for submersible service.

The license provided some evidence in the form of memos, requisition forms, motor test records and material receipts which suggested that submersible qualified motors may have been installed at some point several years ago. The licensee could not, however, provide positive documentation. Nevertheless, the licensee had committed to install submersible qualified MOVs and controls did not exist or were not effective to ensure submersible qualification was maintained. In this case, the licensee deviated from a written commitment in that the valves were not maintained as qualified for submersible service as stated in the FSAR.

The licensee subsequently determined that the valves were not required to be qualified for submersible operation on the basis that a flooding event and a design basis accident occurring simultaneously was not within the plant design basis. The inspector reviewed the licensee's draft 50.59 evaluation while on site and the final versions after they were issued, and did not identify any further concerns. The licensee indicated that they planned to correct the FSAR. This deviation from a commitment is not being cited because subsequent operational philosophy regarding hurricanes and subsequent modifications to Unit 1 ICW pumps to delete the water lubricating system have negated the safety significance.

(2) CCW temperature control valves TCV 14-4A and 14-4B fail open upon loss of instrument air but were not described in the Unit 1 FSAR CCW section.

The licensee provided the inspector with sections of the FSAR which adequately described valves TCV 14-4A and 14-4B (sections 7.3.1.3.2 and 9.2.1.5, table 9.2-2, and figure 9.2-1). The inspector had no further questions on this point.

(3) ICW valves FCV 21-3A and 3B isolated the non-essential lubricating water header upon SIAS but were not described in the FSAR.

The licensee provided the inspector with FSAR table 7.3-2 and figure 9.2-1a, which described valves FCV 21-3A and 21-3B. The inspector had no further questions on this point.

(4) The FSAR incorrectly referenced a deleted section which described recirculation operation between the discharge and intake canals for biofouling control.

The licensee pointed out that recirculation was proposed at one point in time and actual modifications had been initiated, but subsequently terminated. FSAR drawings 9.2-1b and 9.2-1e accurately depicted the as-built status. The inspector reviewed the licensee's currently proposed FSAR correction. The inspector determined that this error did not represent a significant concern.

(5) The FSAR did not include aspects of the self-lubrication modification on the 2A ICW pump.

The inspector determined that a weakness existed with promptly closing out the design change package in order to ensure that the FSAR is updated. The licensee conducted a review and determined this to be an isolated example.

(6) Section 9.2.7 of the FSAR incorrectly described the UHS by discussing only two of three intake pipes.

The inspector found that FSAR section 9.2.3 and figure 9.12-1b describe the three intake pipes for the UHS.

c. (Closed - Units 1 and 2) Deficiency Item 335,389/91-201-02, Inadequate Training Materials.

Several examples of inaccurate or incomplete descriptions of the ICW System were identified in training documents. Examples included the following:

- strainer mesh sizes were incorrect,

- ICW self-lubrication modification was not implemented in all training documents in a timely manner,

- documents incorrectly described cross-connected operation of the ICW system,

- documents omitted unit 2 specific TCV closure limits,

- some setpoints were inaccurate, and

- annunciator listings did not match verbatim the control room annunciator.

The inspector reviewed the deficiencies and determined that while weaknesses may exist for ensuring accurate training materials, the deficiencies were minor in nature and did not represent a safety significant concern. The inspector reviewed corrected training materials including an RCO Self Study Test on Cooling Water Systems (0704201) and a SNPO Lesson Text on Component Cooling Water System (0511016). The inspector additionally determined that other training material deficiencies were being adequately addressed.

It appears that the licensee's Administrative Procedure AP005766, Training Resources, Information and Material Control, was not followed in that review of plant modifications for incorporation into training material was not adequate and resulted in the discrepancies. This NRC identified violation is not being cited because criteria specified in Section VII.B of the NRC Enforcement Policy were satisfied. This is identified as NCV 335,389/92-05-03, Inadequate Training Materials.

d. (Closed - Units 1 and 2) Deficiency Item 335,389/91-201-03, ICW Pump C and Header Inoperability.

This item involved potential inoperability of the C ICW pump due to not adequately demonstrating operability of the pump and its associated actuation circuitry.

The licensee determined that the C ICW pump start feature on SIAS was not required to be tested because during conditions when the pump was required to be operable, the pump would be running and would not require an auto start signal.

The inspector questioned the licensee concerning a Loss of Offsite Power actuation signal and reviewed electrical logic drawings to determine if the C ICW pump was adequately tested. The inspector determined that following a Loss of Offsite power, the C pump would trip and later be sequenced back after the bus was energized by the diesel generator. The logic associated with this, including relays and contacts, was not tested at any periodicity. Technical Specification surveillance 4.8.1.1.2.e.4 requires in part that a loss of offsite power be simulated every 18 months and that auto-connected shutdown loads be verified to energize through the load sequencer. Test procedures failed to adequately demonstrate the ability of the C ICW pump logic to perform this function. This is VIO 335,389/92-05-04, Failure to Adequately Test the C Intake Cooling Water Pump.

e. (Closed - Units 1 and 2) Deficiency Item 335,389/91-201-04, Inservice Testing IST Deficiencies.

(1) One concern involved the testing of manual valves SB-21211 and SB-21165. The licensee's IST program dated January 3, 1990 identified these valves to be exercised quarterly. The licensee subsequently determined that these valves were not required by Section XI to be in the program and never initiated testing on them. The licensee did not obtain prior NRC approval for this change. Prior approval is not required as indicated in the response to question 62 of the October 25, 1989 NRC letter, Minutes of the Public Meetings on Generic Letter 89-04. The concern was that the licensee failed to update their IST program and inform the NRC of the change. The inspector reviewed further guidance in the referenced letter (question 61) which indicated that the NRC staff should have the current IST program being implemented. The inspector determined that this example represented a weakness in not maintaining an accurate listing of all valves in the program. However, in that these valves were never required by the code to be tested and were inadvertently added to the list, the licensee's failure to promptly revise their program does not represent a significant concern. Additionally, the licensee was able to show the inspector that these valves were in fact exercised on a quarterly basis during surveillance testing of ICW pump discharge check valves per Administrative Procedure 1-0010125A, Surveillance Data Sheets. The licensee planned to correct the program. The inspector had no further questions on this point.

(2) A second concern involved the testing frequency of the valves TCV-14-4A and 14-4B on Unit 1. The licensee had been testing the valves during cold shutdown. The valves were classified as Category B power operated valves. Code requirements for testing include stroke valve timing every three months. The licensee's IST program valve table specified a test frequency of cold shutdown and referenced relief request VR-35. VR-35 requested relief from timing the valve and provided a basis indicating that measurements of valve closure times are not practical. VR-35 did not request nor provide a basis for testing the valve at the reduced frequency of cold shutdown. Further, VR-35 stated that alternate testing would be done on a quarterly frequency.

The licensee's program was approved on an interim basis on October 17, 1990. This granted relief to exempt valve timing for the valves. No approval was granted for a reduced test frequency.

The inspector concluded that the licensee's submittal was inconsistent. The NRC granted relief from valve timing. Therefore, the valves were required to be tested every three months. This is identified as a violation of the requirements of the licensee's IST program, Failure to Test TCV-14-4A and 14-4B every three months. This is VIO 335/92-05-05, Failure to Test Certain Valves Quarterly as Required by the Inservice Test Program.

The inspector reviewed the licensee's revised submittal of October 23, 1991 which included revision 3 to relief request VR-35. Further errors were identified with the request in that the requirements for check valve tasting were incorrectly referenced. Additionally, it was not clear whether the licensee considered the valve to be power operated or fail safe.

8. Followup of Headquarters and Regional Requests (92701)

During the inspection period, a survey on maintenance backlog was performed for the NRC Region II Office.

9. Review of Component Cooling Water Temperature Control System (Part of the Intake Cooling Water System) (92701)

a. While reviewing Unit 1 ICW system operation, the inspector observed that: (a) ICW TCVs I-TCV-14-4A and B had a failure mode that may not have been previously evaluated, and (b) the air-operated controls for the temperature control valves may not have the proper qualifications for the safety functions performed.

If instrument air were lost:

- The temperature control valves themselves and their spring-open/air-close Bettis operators were designed to fail open, and were Seismic Category I and safety-related.

- The qualification status of the remaining air-operated control components would not matter.

If instrument air were not lost:

- The temperature control valves themselves and their spring-open/air-close Bettis operators did not have physical stops preventing them from being shut to less than some minimum accident flow position.

- Failure modes of the air-operated controls for the temperature control valves did not appear to be analyzed.

- The air-operated controls for the temperature control valves were considered by the licensee to be non-safety-related and non-seismic. The Unit 1 components were located in exposed locations on the CCW platform.

b. A detailed control system audit followed. The inspector approached the review by: reviewing FSAR requirements and statements; reviewing system modifications and associated analyses, either planned or accomplished, that were not in the FSAR; reviewing the component vendor manuals for potential design input; reviewing the physical installation; determining what surveillance or maintenance program elements have been applied to these components; and determining if these components are being used to accomplish an actual safety-related purpose.

c. Control System Audit Results:

(1) The FSAR review basically found that the only instrument air failure discussed was total loss of instrument air. There was also a failure mode listed where one of the two temperature control valves would fail to open (for undefined reasons). The temperature control valves themselves, and the attached Bettis brand operators, were identified as safety-related and qualified for seismic category I, but the Bailey valve positioners, the associated pneumatic TICs, and the related pneumatic relays and regulating valves (reducers) were not designed as safety-related or seismic. Control components were found to actually be non-safety-related per analysis.

(2) Plant change PCM 005-190, not yet included in the FSAR, was reviewed. The PCM was performed on Unit 1 in the fall of 1991. Its main purpose, per the plant maintenance staff, was to replace obsolete non-safety-related control components with newer safety-related control components. The maintenance department focus when requesting this change was on maintenance and availability of parts, having nothing to do with the system safety analysis. However, the engineering analysis applied to the modification stated very strongly that these were required to be safety-related to function in the case of an accident without loss of instrument air. This analysis included a markup of the FSAR deleting the statements that the control circuits were not safety-related and adding statements that they were safety-related and had to function following an accident. This analysis applied to:

- TICs, which produced an air pressure signal representing a temperature measurement;

- Air pressure limiting relays in the TIC signal path, since the TCVs closed on increasing air pressure and these relays established the minimum TCV opening (most closed position); and

- The common air pressure regulator that reduced the supply air to the operating air pressure for the TICs and air pressure limiting relays.

The above analysis stated that this installation included a positive valve position stop going closed and a positive valve position stop going open, with the valve operating range between those stops. Thus, the valves were open far enough for safe shutdown flow yet restrained from exceeding pump runout flow. This was found to be in error. The minimum valve position stop was not a hard stop at all, it was established by the pneumatic control system air relay setting discussed above. While perhaps open enough for safe shutdown, it was less than the minimum system accident (LOCA) flow. It was based on cavitation in the pipe and downstream of the valve and was not based on safe shutdown or accident flows.

The actions taken by the utility did not address the presently non-safety-related Bailey positioners, or Fisher volume booster relays, or Fisher air reducer valves mounted on the TCVs themselves. A future PCM, also based on obsolete equipment upgrade, is planned to address them.

(3) The vendor manual and physical installation review found that both the TIC and the air relay vendor manuals specified limiting air pressures significantly less then the air supply pressure. Both the original and the newly-installed reducing valves vendor manuals required that, if components downstream could be damaged by upstream pressure, then a full flow relief valve must be installed. There were no relief valves installed in this new design.

(4) Interviews of instrumentation and control staff personnel showed that TIC control loop equipment was on an 18 month inspection and calibration cycle.

(5) The inspector concluded from literature and installation reviews that the utility has been depending on non-safety-related components, that were installed in a manner contrary to vendor manual requirements and did not have a specific failure mode analysis, to control the functioning of the safety-related TCVs. The non-safety-related components were not backed up by physical minimum valve position stops. The engineering evaluation of PCM 005-191 appeared to have identified a previously unreviewed safety question concerning a previously unrecognized failure mode.

d. Subsequent Licensee Actions

When the inspector inquired about further actions that would appear to be warranted upon the licensee recognizing the subject conditions during Summer, 1991, the licensee subsequently stated that last summer's analysis was in error, though it had been signed by a number of engineers, had been reviewed by the Facility Review Group - the technical specification onsite safety review group, and the modification had subsequently been completed on Unit 1.

- New material provided included a special study of the licensing basis and a probabilistic risk assessment. The licensee stated that the text of PCM 005-190 would be rewritten.

- Interviews with licensee engineers found that the licensee considered the licensed basis of St. Lucie to not include a seismic event coincident with a LOCA - which would challenge the ICW system from a heat removal basis. A seismic event is postulated coincident with a need for safe shutdown - which would not require more than normal heat transfer to the ICW system.

- The licensee stated that it was common nuclear design practice to use air system relief valves only if the components did not bleed air during normal operation - these all did normally bleed air.

- The licensee stated that there are no specific standards for qualification of air-operated control components, therefore highly reliable commercial equipment was satisfactory.

e. Conclusion

At this point, further review is required to determine if the CCW TCVs should be safety-related or not. This matter is URI 335,389/92-05-06, Evaluation of whether or not air controls for CCW Temperature Control Valves should be safety related, pending further NRC review of basic requirements.

10. Exit Interview (30703)

The inspection scope and findings were summarized on March 30, 1992, with those persons indicated in paragraph 1 above. The inspector described the areas inspected and discussed in detail the inspection findings listed below. Proprietary material is not contained in this report. Dissenting comments were not received from the licensee.

Item Number	Status		Description and Reference
335,389/92-05-01	open	IFI -	Seismic Qualification of Racked Out Circuit Breakers, paragraph 2a.
335,389/92-05-02	closed	NCD -	Failure to Maintain Submersible Valve Qualifications as Described in the FSAR, paragraph 7b.
335,389/92-05-03	closed	NCV -	Inadequate Training Materials, paragraph 7c.

Item Number	Status	Description and Reference
335,389/92-05-04	open	VIO - Inadequate Test of ICW Pump, paragraph 7d.
335/92-05-05	open	VIO - Failure to Test Certain Valves Quarterly as Required by the Inservice Test Program, paragraph 7e.
335,389/92-05-06	open	URI - Evaluation of whether or not air controls for CCW TCVs should be safety related, paragraph 9e.
335,389/91-201-01	closed	URI - Preoperational Test Review, paragraph 7a.
335,389/91-201-01	closed	Deficiency Item - Incomplete and Inaccurate FSAR Discussions, paragraph 7b.
335,389/91-201-02	closed	Deficiency Item - Inadequate Training Materials, paragraph 7c.
335,389/91-201-03	closed	Deficiency Item - ICW Pump C and Header Inoperability, paragraph 7d.
335,389/91-201-04	closed	Deficiency Item - Inservice Testing IST Deficiencies, paragraph 7e.

11. Abbreviations, Acronyms, and Initialisms

AC	Alternating Current
AFW	Auxiliary Feedwater (system)
ANSI	American National Standards Institute
AP	Administrative Procedure
ASME Code	American Society of Mechanical Engineers Boiler and Pressure Vessel Code
ATTN	Attention
cc	Cubic Centimeter
CCW	Component Cooling Water
CEA	Control Element Assembly
CFR	Code of Federal Regulations
CWO	Construction Work Order
DC	Direct Current
DEH	Digital Electro-Hydraulic (turbine control system)
DPR	Demonstration Power Reactor (A type of operating license)
EC	Emergency Coordinator
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EOP	Emergency Operating Procedure
EPA	Environmental Protection Agency
EPIP	Emergency Plan Implementing Procedure

ESF	Engineered Safety Feature
FCV	Flow Control Valve
FLO	ABASCO Standard Specification for an FPL Project
FMEA	Failure Modes and Effects Analysis
FPL	The Florida Power & Light Company
FRG	Facility Review Group
FSAR	Final Safety Analysis Report
GL	[NRC] Generic Letter
gpm	Gallon(s) Per Minute (flow rate)
HX	Heat Exchanger
Hz	Hertz (cycle per second)
I&C	Instrumentation and Control
ICW	Intake Cooling Water
IFI	[NRC] Inspector Followup Item
INPO	Institute for Nuclear Power Operations
IST	InService Testing (program)
JPN	(Juno Beach) Nuclear Engineering
LCO	TS Limiting Condition for Operation
LOCA	Loss of Coolant Accident
LOI	Letter of Instruction
MFP	Main Feed Pump
MOV	Motor Operated Valve
MV	Motorized Valve
NCD	Non Cited Deviation
NCR	Non Conformance Report
NCV	Non-cited Violation (of NRC requirements)
NEMA	National Electrical Manufacturers Association
NPF	Nuclear Production Facility (a type of operating license)
NPS	Nuclear Plant Supervisor
NPWO	Nuclear Plant Work Order
NRC	Nuclear Regulatory Commission
NRR	NRC Office of Nuclear Reactor Regulation
ONOP	Off Normal Operating Procedure
OP	Operating Procedure
PCM	Plant Change/Modification
PM	Preventive Maintenance
psig	Pounds per square inch (gage)
PSL	Plant St. Lucie
QA	Quality Assurance
QI	Quality Instruction
RCO	Reactor Control Operator
REA	Request for Engineering Assistance
Rev	Revision
rpm	Revolutions per Minute
RPS	Reactor Protection System
RTGB	Reactor Turbine Generator Board
RTV	A Type of silicone rubber
RWP	Radiation Work Permit
RWT	Refueling Water Tank
SAMA PMC	Standard of Unknown Origin
SB	Safety Train B

SFP	Spent Fuel Pool
SG	Steam Generator
SIAS	Safety Injection Actuation System
SNPO	Senior Nuclear Plant [unlicensed] Operator
SRO	Senior Reactor [licensed] Operator
St.	Saint
TCV	Temperature Control Valve
TIC	Temperature Indicator Controller
TQR	Topical Quality Requirement
TR	Temperature Recorder
TS	Technical Specification(s)
UHS	Ultimate Heat Sink
URI	[NRC] Unresolved Item
VIO	Violation (of NRC requirements)