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

Report Nos.: 50-335/91-14 AND 50-389/91-14

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: June 18 - July 15, 1991

Inspectors: for S. A. Elrod, Senior Resident Inspector — 8/2/91 Date Signed

for M. A. Scott, Resident Inspector — 8/2/91 Date Signed

Approved By: K. D. Landis, Section Chief — 8/2/91 Date Signed
Division of Reactor Projects

SUMMARY

Scope:

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

Results:

Operational controls, particularly during a Unit 1 trip and recovery, were good. Performance of emergency diesel generator preventive maintenance on two separate occasions created operability concerns, but they were adequately resolved. Engineering and contractor control of work at the common ocean intake structure was positive.

In the areas inspected, violations or deviations were not identified.

REPORT DETAILS

1. Persons Contacted

   Licensee Employees

   D. Sager, St. Lucie Site Vice President
   * G. Boissy, Plant Manager
   J. Barrow, Fire Prevention Coordinator
   H. Buchanan, Health Physics Supervisor
   * C. Burton, Operations Superintendent
   * R. Church, Independent Safety Engineering Group Chairman
   * R. Dawson, Maintenance Superintendent
   R. Englmeier, Site Quality Manager
   * R. Frechette, Chemistry Supervisor
   * J. Holt, Plant Licensing Engineer
   C. Leppla, I&C Supervisor
   * L. McLaughlin, Plant Licensing Superintendent
   * A. Menocal, Mechanical Maintenance Supervisor
   * L. Rogers, Electrical Maintenance Supervisor
   N. Roos, Services Manager
   C. Scott, Outage Management Supervisor
   * D. West, Technical Staff Supervisor
   * J. West, Operations Supervisor
   W. White, Security Supervisor
   D. Wolf, Site Engineering Supervisor
   G. Wood, Reliability and Support 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
   * M. Scott, Resident Inspector

   * Attended exit interview

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

2. Review of Plant Operations (71707)

   Unit 1 began the inspection period at power. The unit tripped on July 1 from low SG water level resulting from a maintenance personnel error. Following testing of "old style" CEAs, Unit 1 was restarted on July 3 and ended the inspection period at power - day 12 of power operation.

   Unit 2 began and ended the inspection period at power - day 221 of power operation.

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 and equipment conditions were randomly verified both locally and in the control room. The following accessible-area ESF system 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 SFP,

Unit 2 RAB Tunnel, and

Unit 2 Switchgear.

On June 19, a Unit 1 SFP leakage tell-tale drain was found with its leak detection bag filled with about 2 pints of fluid, some of which had spilled onto the floor of the leak collection pit. A series of pipes from collection points around the SFP exterior are routed to a low point pit in the fuel handling building with each pipe terminated with an open, bagged, valve. The same valve and bag, without the fluid, had been visually surveilled by licensee personnel just a few days previously on June 14. The licensee promptly sampled the fluid, determined that it was not from SFP leakage, and installed a new bag. The following day, the newly-installed bag was partially filled with fluid and was changed. A new bag contained no fluid four days later.

The licensee concluded that a recent test caused the fluid in the SFP leakage tell-tale. The licensee had intentionally turned off SFP cooling to determine the SFP heatup rate anticipating SFP heat exchanger flange work during the upcoming Fall, 1991, refueling

outage. When normal cooling was resumed, condensate was believed to have formed on the outside tank surfaces.

Licensee actions and followup were adequate in this regard.

b. Plant Operations Review

The inspectors periodically reviewed shift logs, operations records (including data sheets), instrument traces, and records of equipment malfunctions. This review included control room logs, 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 ensure 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 the following tagouts (clearances):

2-6-72 MV 14-4 "B" CCW header to "C" CCW pump, breaker 2-42424, and

1-7-25 1A EDG, Lubricate and Inspect.

These clearances were properly executed.

On June 20, an operator reported that, earlier in the shift, the starting air tanks for 2A EDG had been found at about 110 psig vice the normal range of 150-200 psig and that the operator had then manually started the air compressor and restored tank pressure to normal. Such a condition would require multiple failures in diverse and redundant pressure sensing systems for air compressor control and for separate annunciation. Upon receiving the report, the licensee promptly started the 2B EDG to demonstrate operability per TS 3.8.1.1, AC Sources, action statement "b", then extensively investigated the reported condition. The air compressor start control circuit was troubleshot per NPWO 6024/64. Scope Change 1 extended the troubleshooting scope to the low-air-pressure alarm circuit. Troubleshooting included wire connector tightness checks and demonstration that each pressure switch would individually start the compressor or give an alarm, as appropriate. The as-found pressure switch settings were close to design values, but calibrations were performed anyway. Even though the condition could not be duplicated, the operators began recording air tank pressure each four hours to detect trends and ascertain system operation. No unusual conditions were observed over a period exceeding three weeks. The licensee continues to watch the system closely.

The inspector concluded that the licensee's actions in this area were dynamic, thorough, and appropriate. The inspector had no further questions.

On June 26, following various PMs and a field circuit modification, 2B EDG failed the monthly surveillance run used as a retest. The EDG's two engines started and ran under mechanical speed control but the generator failed to produce voltage at first. Initial indications were that the field flash circuit failed to perform in a timely manner. The licensee was able to repeat the failure under test conditions per NPWO 7100/62. A field flash control circuit relay, energized when an EDG start signal is present, was found without electrical continuity through the coil. After the 2B EDG was satisfactorily tested, the 2A EDG was started on June 26 per TS 4.8.1.1.b (i.e., start the other operable EDG within 24 hours of the failure of the first EDG). This being the second valid failure of 2B EDG this year, the surveillance requirement was shifted from monthly to weekly until seven successful starts occurred. Rather than establish a special weekly test routine, the licensee elected to test 2B EDG daily until the seven successful starts occurred, then return to a monthly test schedule per the established program. The test data for June 29 was reviewed with no comments.

The inspector concluded that the licensee's approach to this failure reflected a high sensitivity to the importance of the EDGs.

On July 1, Unit 1 tripped from 100 percent power due to a personnel error. I&C personnel were removing a malfunctioning SG level instrument for repair at the time of the event. The "A" train digital feedwater controllers went dark and several other instruments failed "as is," including one SG level chart recorder. The control board operator attempted to feed the 1A SG, but its water level went low, tripping the reactor via the RPS. Post trip activities were well controlled. The operations staff performed the post trip recovery actions and review required by procedure 1-EOP-02, Rev 4, Post Trip Recovery. Aside from the feedwater regulating valves discussed below, all equipment operated properly and the unit was safely shut down to Mode 3.

Licensee management and the STA arrived immediately to assist in discovering the trip's root cause. The trip's proximate cause was promptly found. While removing LIC 9013B, 1A SG level Sigma gage, I&C personnel caused a short circuit via neutral power wire and tripped the circuit breakers for both the 100 percent and 15 percent "A" train feedwater regulating valve control circuits. The trip's root cause was being explored by the licensee at the end of the inspection period. The preliminary root causes were:

- tightness of the work area,

- incomplete understanding of circuits involved, and

- personnel error in the management of a lifted lead.

Once the causes for the Unit 1 trip were understood, the licensee began pre-startup activities. Portions of the Unit 1 pre-startup preparations and startup on July 2-3 were observed on station and in the control room, including the following activities:

- OP 1-0110056, Rev 19, Surveillance Requirements for Shutdown Margin, Modes 2, 3, 4 and 5 Subcritical,
- OP 1-080050, Rev 11, Main Steam Isolation Valve Periodic Test,
- OP 1-1210051, Rev 11, Wide Range Nuclear Instrumentation Channel Functional Test,
- OP 1-1400054, Rev 2, Loss of Turbine Hydraulic Fluid Pressure,
- OP 1-1400059, Rev 17, RPS - Periodic Logic Matrix Test, and
- LOI-0-40, Rev 0, Testing of "Original Design" Type #1 Control Element Assembly.

Original Design CEAs were tested and found operable per LOI 0-40, Rev 0, Testing of "Original Design" Type #1 Control Element Assembly. This insertion test individually confirmed operability of these 20 CEAs following the reactor trip per a commitment to the NRC (see IR 335,389/91-10, page 4). These CEAs will be replaced with a later design during the Fall 1991 refueling outage. The above LOI was scheduled to be performed August 30, 1991, barring a reactor trip. The next scheduled CEA exercise would be three months from the above trip, or 18 days before the planned refueling outage. The licensee is considering a request for deferral of this final CEA test based on the previous satisfactory testing (including the above) and proximity to the shutdown.

Shutdown CEAs were fully withdrawn at 5:00 a.m. on July 2 and reactor startup commenced at 5:20 a.m. At 6:20 a.m., regulating CEA group 1 was reinserted and the startup deferred because CEA 30 had intermittent position indication. Following the licensee's safety and regulatory review of CEA 30 performance, startup was recommenced at 4:52 p.m. Unit 1 attained criticality at 6:55 p.m. and the generator was connected to the electric grid at 6:15 a.m. on July 3.

Operator performance and management oversight during this startup were professional.

On July 5, the Unit 1A EDG governor limit switches were inspected per electrical NPWO 5492/61. That inspection was one of several countermeasures for an April, 1991, governor limit switch failure on 2B EDG. Other mechanical PMs were also performed per other NPWOs. Following completion of the PMs, 1A EDG was started for

post-maintenance operability and periodic surveillance testing but failed to accept more than about 1100 KW, 31 percent load. The EDG was stopped.

Licensee troubleshooting found two adverse conditions: the governor dial panel had bound the speed setting knob, much like an occurrence resulting from a similar 2B EDG inspection on June 14, and the bound-up speed setting knob had caused the speed setting motor to burn out. These were corrected and the engine satisfactorily retested. Licensee compliance with TS 4.8.1.1.b (i.e., start the other operable EDG within 24 hours of the failure of the first EDG) is discussed in paragraph 6.

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.

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.

The inspectors concluded that the licensee's approach to plant operations during this evaluation period was conservative, with serious consideration of potential safety and regulatory issues.

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. I&C 2-1400052, Rev 18, Engineered Safeguards Actuation System Functional Test,

b. OP 1-0110050, Rev 21, Control Element Assembly Periodic Exercise,

c. AP 1-0010125A, Rev 21, Surveillance Data Sheets, Data Sheet 14, 1C Charging Pump,

d. OP 1-0700050, Rev 36, Auxiliary Feedwater Periodic Test, Data Sheet "C", 1C AFW Pump,

e. AP 1-0010125, Rev 84, Check Sheet 6, Paragraph 2.A., Test Run of "A" Train SBVS,

f. AP 1-0010125, Rev 84, Check Sheet 4, ECCS Exhaust Fan 1 HVE 9A, Fan Run and Damper Positions, and

g. OP 2-0700050, Rev 24, Auxiliary Feedwater Periodic Test, Data Sheet "C", 2C AFW pump. Three QI 11 PR/PSL-2 test forms, documenting post-maintenance tests for the PMs listed below, were completed by the operators upon completing the surveillance. The three PMs were:

   - NPWO 8674/62, AFW Pump Lubrication,

   - NPWO 8650/62, Pump Turbine Drive Lubrication, and

   - NPWO 8675/62, Turbine Governor Lubrication Leak Repair.

   The licensee has been focusing on completing all PM work related to a component at one time in concert with the component surveillance schedule.

h. Additionally, the tests discussed in paragraph 2 above for the Unit 1 restart were observed.

The observed tests were performed satisfactorily with no negative comments.

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 ensure that priority was assigned to

safety-related equipment. Portions of the following maintenance activities were observed:

a. On June 25, inspectors observed periodic maintenance of the motor control center controller for MV 2525, Boron Flow Control Valve. The work was controlled by NPWO 4643/62 and MP 0950177, Rev 2, Periodic Maintenance of 600 Volt and Below Motor Control Centers/ Starters. The procedure and the supporting documents and drawings were issued in a notebook - a very efficient technique. The PM included wire tracing to ensure that the wiring matched the drawing - an effective means of ensuring quality. The procedure required that all field connections be disconnected in anticipation of removing the controller to the shop for work. TC 2-91-102 was properly obtained to disconnect only certain field wires because the controller chassis could be cleaned and inspected after partial removal and was not being taken to the shop. The workmanship was excellent and the procedure well engineered and presented.

   On June 26, MP 0950177, Rev 3, was distributed. Comparison to Rev 2 discussed above showed that Rev 3 incorporated TC 2-91-102 as a permanent revision. Detailed procedure review developed several questions concerning the meaning of signature spaces for conditional procedure steps, acceptance criteria for relay contact inspections, and post-installation operational test requirements. While these areas were found satisfactory for this performance of the procedure, the licensee upgraded the procedure in these areas to facilitate future performance. That upgrade was contained in TC 2-91-120.

b. NPWO 6004/61 provided the work control for satisfactorily changing out a Unit 1 AFAS bistable comparator card which was found faulty during a monthly surveillance test. This separate NPWO was generated to troubleshoot and repair in lieu of scope changing the surveillance NPWO - a sound methodology.

c. NPWO 7012/62 provided the work control for calibrating instrument loop F14-1B, whose output was FT/FIS 14-1B, CCW HX 2B flow. A loop instability, or reading roughness, had been observed during the last 2B CCW pump surveillance test. The square root calculator was found to be slightly out of adjustment and the the output indicator's slide wire was found to be pitted, causing uneven indicator motion. These were replaced. The "as found" FT/FIS calibration data did not void previously satisfactory pump surveillance test findings.

d. On June 26, the performance of Unit 2 MFIV PM and surveillance test were integrated per procedures 2-M-0018, Rev 25, Mechanical Maintenance Safety Related Preventive Maintenance Program, PMs 01601 through 01604, and per OP 2-0810050, Rev 14, MFIV/MSIV Partial Stroke. Site QA inspectors expressed concerns regarding coordination between the two procedures and departments. The NRC inspector had no additional comments concerning the safety-related aspects of these. The surveillance test addressed the TS and safety-related aspects of

the valves, but not all the elements needed for long term operation. The licensee tested instrument air joints for leakage when requested by the inspector. A number of these were briskly leaking air. The air leaks themselves did not directly jeopardize valve operation, but do load the instrument air system. Since this leakage was informally identified to the licensee several months ago, higher level managers were informed this time. Repair of the air leaks will be routinely followed up by the inspectors during other inspection activity.

e. NPWO 6039/64 was the work control document for the replacement of power supply 209, which powered LT/LIS-07-2B for the RWT level. The appropriate sensitive systems pre-review was conducted per AP 0010142, Unit Reliability - Manipulation of Sensitive Systems, Rev 6. QC personnel were present for a surveillance of the work. Appropriate retesting occurred per I&C 2-1400052, Rev 18, Engineered Safeguards Actuation System Functional Test.

f. The licensee has been supportive and instrumental in initiating an EPRI RCP testing program. The licensee has provided financial and personnel support to a research effort regarding the detection of RCP shaft and other potential failures. In April of this year the group held an annual conference in Phoenix, Arizona. A manager in the St. Lucie reliability support group was chairman of the instrumentation committee for the program. The test RCP, which is in place at a contracted facility (Ontario Hydro), will be instrumented for the detection of shaft cracks and hopefully will discriminate such a failure from other machine faults. Testing was scheduled to begin later this year.

g. On June 20, the inspectors reviewed the progress of an important capital project at the common unit intake structure. PCM 101-990D was the controlling package for the refurbishment and improvement of the velocity caps for the three salt water cooling intake pipes in the Atlantic Ocean. The inspectors, accompanied by FPL and primary contractor managers, toured both the construction platform at the ocean intake structure and the barge-mounted concrete plant which was moored in Ft. Pierce, Florida. Two of the velocity caps had sustained damage from deterioration over the years and all three caps were being replaced.

All visible evidence supported the conclusion that the velocity cap project was well controlled. Both FPL and contract personnel were well versed in project details and implementation. FPL personnel understood their role in the project and routinely visited the work site. The contractor had a well controlled operation with knowledgeable personnel on hand. Work appeared to be proceeding smoothly and within schedule. The cap repairs were scheduled to be completed during the Fall, 1991, Unit 1 refueling outage.

Most maintenance activities were well controlled. The PM activities involving the EDG governors were exceptions, in that they caused two EDGs to not operate properly.

5. 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.

As discussed in paragraph 2 above, the inspectors followed up on the Unit 1 trip of July 1. As the report period was ending, the licensee was finalizing the in-house event report leading to the subsequent LER. The root cause evaluation was under development.

6. Followup of Unresolved Items (Units 1 and 2) (92701)

(CLOSED - Units 1 and 2) URI 335,389/91-12-01, Applicability of the Requirement to Run an Operable EDG Upon Failure of One EDG to Pass a Post-Maintenance Test.

During recent NRC resident inspections at St. Lucie, the inspector identified a conflict in interpretation of Unit 1 and 2 Technical Specification (TS) 3/4.8.1, A.C. Sources, Action Statement "b". That action statement states, in part, that " . . . ; and if the EDG became inoperable due to any cause other than preplanned preventive maintenance or testing, demonstrate the OPERABILITY of the remaining OPERABLE EDG by performing Surveillance Requirement 4.8.1.1.2a.4 within 24 hours*; restore . . . ." A footnote applies to this statement, as follows: "*This test is required to be completed regardless of when the inoperable EDG is restored to operability." This URI concerned whether the TS leeway concerning not starting the other EDG within 24 hours applied only when removing one EDG for PM or test or whether it also applied when the EDG subsequently failed a post-maintenance operability validation or combined operability validation and periodic surveillance.

At St. Lucie, routine equipment PMs are generally scheduled for performance just prior to the periodic surveillance test. The equipment is removed from service, the PMs performed, then the periodic surveillance performed as both the post-PM operability test and the periodic surveillance. The equipment would be returned to service upon satisfactory completion of the surveillance. As needed, additional observations such as valve stroke time or bearing temperatures may be made following specific PMs.

On two occasions, June 14, 1991 (2A EDG), and July 5, 1991 (1A EDG), in conjunction with several mechanical PMs, the EDG governor limit switches were inspected as a PM vice corrective maintenance. That inspection was one of several countermeasures developed for an April, 1991, governor

limit switch failure on 2B EDG. The inspection involved removing the governor dial panel (a four-screw face plate), inspecting the components mounted behind it both visually and by manipulation, removing the speed setting motor from the governor and inspecting the pinion visually, then reinstalling the components.

Following completion of the various PMs, the EDGs were started for combined post-maintenance operability and periodic surveillance testing. In both the June 14 and July 5, 1991, cases, the governor dial panel was found binding the speed control knob and preventing EDG loading. This was quickly adjusted and the EDGs retested. During the July 5 retest, the 1A EDG again failed to load. Further troubleshooting found that the bound-up speed control knob had caused the speed setting motor to burn out. This motor was replaced and the engine satisfactorily tested.

When one subject EDG failed to start on June 14, and the other failed the first start attempt on July 5, the licensee did not run the "other train" EDG within 24 hours as discussed above because the EDG start attempts were "associated with" (i.e., following) preplanned maintenance and the failures to start were caused by preplanned [poorly performed] preventive maintenance. When the 1A EDG failed its second start on July 5 and the cause was not immediately obvious, the licensee then test started the 1B EDG per TS. Licensee post event analysis concluded that this 1B EDG TS start had not actually been required because the 1A EDG speed setting motor failure was caused by the 1A EDG PM that was being retested.

The licensee's position, not plainly supported in TS, was:

a. The TS leeway applied to the act of removing the EDG from service for preplanned preventive maintenance or testing.

b. Once the EDG was out of service for PMs or testing, the TS leeway would also apply during that period to all conditions related to the PM or test, including poorly performed PMs or consequent damage, until the EDG was FORMALLY returned to service.

c. Totally unrelated failures would still be considered to cause a new inoperability.

The licensee's interpretation was confirmed to be valid during a July 15, 1991, conference call with NRC Region II and NRR managers. This item is closed.

7. Fire Protection (Units 1 and 2)(64704)

The licensee satisfactorily tested the 1A and 2A startup transformer sprinkler/deluge system in accordance with procedure MP 0959063, Rev 7, Deluge and Sprinkler Test. Appropriate equipment such as the fire pumps and startup transformers were taken out of service for the test. With the startup transformers out of service, the EDGs were tested per TS. All

sensors, alarms, spray heads, and associated fire protection system subcomponents operated as required.

The licensee's performance in this area was very professional.

8. Followup of Headquarters and Regional Requests (Units 1 and 2)(92701)

The inspector reviewed a safety concern identified by NRC Region III concerning the potential for certain large electrical circuit breakers to experience a power failure in the CLOSE circuit and not be available for their safety-related function, yet not self-annunciate this failure. This was believed to perhaps be applicable to St. Lucie Unit 1 because of the construction permit date.

Review of CWDs for the EDG output breakers and the large safety-related pump breakers showed that these CLOSE circuits had a local amber ready light and a relay providing control room annunciation. Power failure, such as a loose or blown fuse, or several other failure modes, would extinguish the local amber light and annunciate the appropriate Start Failure alarm in the control room. The inspector concluded that this concern was not applicable to St. Lucie.

9. Exit Interview (30703)

The inspection scope and findings were summarized on July 19, 1991, 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
335,389/91-12-01	closed	URI - Applicability of the Requirement to Run an Operable EDG Upon Failure of One EDG to Pass a Post-Maintenance Test, paragraph 6.

10. Abbreviations, Acronyms, and Initialisms

AFAS	Auxiliary Feedwater Actuation System
AFW	Auxiliary Feedwater (system)
AP	Administrative Procedure
ATTN	Attention
CCW	Component Cooling Water
CEA	Control Element Assembly
CFR	Code of Federal Regulations
CWD	Control Wiring Diagram
DPR	Demonstration Power Reactor (A type of operating license)
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator

EOP	Emergency Operating Procedure
EPRI	Electric Power Research Institute
ESF	Engineered Safety Feature
FIS	Flow Indicator/Switch
FPL	The Florida Power & Light Company
FT	Flow Transmitter
HVE	Heating and Ventilating Exhaust (fan, system, etc.)
HX	Heat Exchanger
I&C	Instrumentation and Control
IR	[NRC] Inspection Report
KW	KiloWatt(s)
LCO	TS Limiting Condition for Operation
LER	Licensee Event Report
LIC	Level Indicator/ Controller
LOI	Letter of Instruction
MFIV	Main Feed Isolation Valve
MP	Maintenance Procedure
MV	Motorized Valve
NPF	Nuclear Production Facility (a type of operating license)
NPWO	Nuclear Plant Work Order
NRC	Nuclear Regulatory Commission
NRR	NRC Office of Nuclear Reactor Regulation
OP	Operating Procedure
PCM	Plant Change/Modification
PM	Preventive Maintenance
psig	Pounds per square inch (gage)
PSL	Plant St. Lucie
QA	Quality Assurance
QC	Quality Control
QI	Quality Instruction
RAB	Reactor Auxiliary Building
RCP	Reactor Coolant Pump
Rev	Revision
RPS	Reactor Protection System
RWT	Refueling Water Tank
SBVS	Shield Building Ventilation System
SFP	Spent Fuel Pool
SG	Steam Generator
St.	Saint
STA	Shift Technical Advisor
TC	Temporary Change
TS	Technical Specification(s)
URI	[NRC] Unresolved Item