MEMORANDUM TO: Joseph W. Shea, Project Manager
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Office of Nuclear Reactor Regulation

FROM: Jan A. Norris, Sr. Project Manager
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SUBJECT: ST. LUCIE UNITS 1 AND 2 - SPENT FUEL POOL SURVEY

This memorandum provides the information requested by the February 8, 1996, memorandum from John Stolz regarding a review of the spent fuel pool practices and current licensing basis.

Attachment: St. Lucie SFP Survey

Docket Nos. 50-335 and 50-389

SL SFP2

ST. LUCIE SPENT FUEL POOL SURVEY

A. Spent Fuel Pool (SFP) System Design

UNIT 1

The system is composed of heat exchanger, filter, ion exchanger, pump suction strainer, ion exchanger strainer, pumps, piping and valves. The system has only one train of components. The cooling portion of the fuel pool system is a closed loop system consisting of two half capacity pumps and one full capacity heat exchanger. For normal refueling discharge conditions, one fuel pool pump and the fuel pool heat exchanger are in service. During abnormal refueling conditions, such as full core discharge, two fuel pool pumps and the heat exchanger are in service. The system is manually controlled from a local control panel. High fuel pool temperature, high and low fuel pool water level, and a low fuel pool pump discharge pressure alarms are announciated in the control room. Makeup to the fuel pool comes from the refueling water tank. The heat exchanger is cooled by component cooling water. The system is designed to provide a minimum of 9 feet of water above the top of the fuel during handling and storage operation.

UNIT 2

The system is composed of heat exchangers, filter, ion exchanger, pump suction strainer, ion exchanger strainer, pumps, piping and valves. The system has only one train of components. The cooling portion of the fuel pool system is a closed loop system consisting of two half capacity pumps and two full capacity heat exchangers. Full capacity condition corresponds to the design condition of a full core placed in the spent fuel pool seven days after reactor shutdown, in adtches, the most recent of which has been cooling for 90 days. For normal refueling discharge conditions, one fuel pool pump and the fuel pool heat exchanger are in service. During abnormal refueling conditions, such as full core discharge, two fuel pool pumps and the heat exchanger are in service. The system is manually controlled from a local control panel. High fuel pool temperature, high and low fuel pool water level, and a low fuel pool pump discharge pressure alarms are announciated in the control room. Makeup to the fuel pool comes from the refueling water tank. The heat exchanger is cooled by component cooling water. The system is designed to provide a minimum of 9 feet of water above the top of the fuel during handling and storage operation.

SLSFP2

SL-1-3

St. Lucie 1

B. SUMMARY OF CLB REQUIREMENTS RE:SPENT FUEL POOL DECAY HEAT REMOVAL/REFUELING OFFLOAD PRACTICES

1. Technical Specification limits are provided for:

TS 3.9.3: 72 hour minimum decay time.

TS 3.9.5: Direct communications between the control room and the refueling station during core alterations.

TS 3.9.6: Manipulator crane shall be used to move fuel assemblies and be operable.

TS 3.9.7: Crane travel with heavy loads (>2000 lbs.) over irradiated fuel is prohibited.

TS 3.9.11: Minimum water level 23 feet above the top of irradiated fuel in the SFP.
TS 3.9.12: At least one fuel pool ventilation system shall be operable.

TS 3.9.13: Maximum load for the spent fuel cask crane shall not exceed 25 tons.

TS 3.9.14: Decay fuel assemblies for 1180 hours (1490 hours for >one-third core) prior to movement of the spent fuel cask into the fuel cask compartment.

2. The fuel pool system is designed to provide shielding for irradiated fuel so that personnel dose rates do not exceed 2.5 mrem/hr; maintain pool temperature below 150 °F under offload conditions; maintain purity and clarity of the SFP, refueling cavity, and refueling water tank water; and maintain water level 9 feet above the irradiated fuel during transfer operations.

3. Design heat load for the normal batch discharge case assumes 18 batches of 80 assemblies discharge to the SFP in 18 month intervals, followed by a discharge of 80 assemblies after 150 hours of decay. With a single pump and heat exchanger in operation, the system can maintain SFP temperature below 134 °F. Time-to-boil assuming cooling was completely lost at the maximum temperature is 13.43 hours. A full capacity pump is available should the first pump fail. [FSAR Section 9.1.3.2] Normal discharge heatload is 16.42×10^6 Btu/hr. [Staff rerack safety evaluation dated 3/11/88]

Does the licensee consider the failure of the fuel pool heat exchanger credible. Having a single heat exchanger does not provide for single failure (this component is passive)

The FSAR describes the normal batch discharge case as a one-third offload. In March the licensee plans to offload a full core. Is it and abnormal offload or do they "normally" off load a full core. If so, change the FSAR.

4. Design heat load for the abnormal batch discharge case assumes 18 batches of 80 assemblies discharge to the SFP in 18 month intervals, followed by a discharge of 217 assemblies with 169 hour of decay. With both pumps and a single heat exchanger in operation, the system can maintain SFP temperature below 151 °F. Time-to-boil assuming cooling was completely lost at the maximum temperature is 5.04 hours. The capability to withstand a single failure criteria was not assumed [FSAR Section 9.1.3.2]. The heat load for the abnormal case is 33.70×10^6 Btu/hr. [Staff rerack safety evaluation dated 3/11/88]

The staff also accepted a single failure of the SFPCS pump with a full core in the SFP. The

maximum temperature reached 167 °F under these assumptions. [Staff rerack safety evaluation dated 3/11/88]

The licensee's FSAR does not describe this scenario (full core offload - single failure). The licensee should be questioned whether a SFPCS single failure under full core offload heatload is part of their licensing basis.

5. The storage capacity for Unit 1 SFP is 1706 fuel assemblies (7 2/3 cores).

6. Boron concentration shall be maintained at a minimum of 1720 ppm.

7. The spent fuel pool is designed to withstand the steady state water temperatures of 217 °F.

8. Makeup sources to the SFP are from: refueling water storage tank, city water storage tank, city water storage tanks via portable fire pump, and the primary water tank. A seismic Category I source is available from the intake cooling water inter-tie (salt) at 150 gpm [FSAR 9.1.3.4.5].

   Lining up seismic makeup using the refueling water tank is complicated. The PM should review the procedure to ensure it exists and that the licensee trains on it periodically.

9. No other implicit or explicit prohibitions exist within the CLB against performing a full core offload for any given refueling outage.

Discrepancies:

None. However, see comments in each section above.

B. SUMMARY OF CLB REQUIREMENTS RE:SPENT FUEL POOL DECAY HEAT REMOVAL/REFUELING OFFLOAD PRACTICES

1. Technical Specification limits are provided for:

TS 3.9.3: 72 hour minimum decay time.

TS 3.9.5: Direct communications between the control room and the refueling station during core alterations.

TS 3.9.6: Manipulator crane shall be used to move fuel assemblies and be operable.

TS 3.9.7: Crane travel with heavy loads (>1600 lbs.) over irradiated fuel is prohibited.

TS 3.9.11: Minimum water level 23 feet above the top of irradiated fuel in the SFP.
TS 3.9.13: Maximum load for the spent fuel cask crane shall not exceed 100 tons.

TS 3.9.14: Decay fuel assemblies for 1180 hours (1490 hours for >one-third core) prior to movement of the spent fuel cask into the fuel cask compartment.

The PM should ask why there isn't a fuel building ventilation TS similar to Unit 1 TS 3.9.12.

2. The fuel pool system is designed to provide shielding for irradiated fuel so that personnel dose rates do not exceed 2.5 mrem/hr; maintain pool temperature below 150 °F under offload conditions; maintain purity and clarity of the SFP, refueling cavity, and refueling water tank water; and maintain water level 9 feet above the irradiated fuel during transfer operations.

3. Design heat load for the normal batch discharge case assumes 11 batches of 80 assemblies discharge to the SFP in 18 month intervals, followed by a discharge of 80 assemblies after 120 hours of decay. With a single pump and heat exchanger in operation, the system can maintain SFP temperature below 131 °F with a CCW temperature of 100 °F. Time-to-boil assuming cooling was completely lost at the maximum temperature is 12.6 hours. A full capacity pump is available should the first pump fail. [FSAR Section 9.1.3.1] Normal discharge heatload is 16.42×10^6 Btu/hr.

4. Design heat load for the full core discharge case assumes 11 batches of 80 assemblies discharge to the SFP in 18 month intervals (the most recent has decayed 90 days), followed by a discharge of 217 assemblies with 168 hours of decay. With both pumps and a single heat exchanger in operation, the system can maintain SFP temperature below 148 °F with a CCW temperature of 100 °F. Time-to-boil assuming cooling was completely lost at the maximum temperature is 3.9 hours. The capability to withstand a single failure criteria was not assumed. The heat load for the abnormal case is 30.3×10^6 Btu/hr [FSAR Section 9.1.3.1]. A single failure was analyzed for this heat load case. The maximum pool temperature under full core offload heatload was found to be less than 160 °F [FSAR 9.1.3.3].

5. Piping and components in the SFPCS are Quality Group C, seismic Category I, designed for a temperature of at least 200 °F. [FSAR Section 9.1.3.2.1, and Table 9.1-6.]

6. Normal makeup sources to the SFP are from the refueling water storage tank and the primary water tank. Three million gallons of makeup are also available from the city water

storage tanks, condensate storage tank, demineralized water tank, and others. A seismic Category I source is also available through hoses from the intake cooling water header. [FSAR Section 9.1.3.3.1]

7. No implicit or explicit prohibitions exist within the CLB against performing a full core offload for any given refueling outage.

Discrepancies:

None

SFP 4

SPENT FUEL STORAGE DATA TABLE

Facility	Name: St. Lucie	Unit Number: Unit 1
Licensee's SFP Contact	Name: M. P. Sharp	Telephone: (407) 694-3340
SFP Related Technical Specifications	Parameters: Electrical Power Systems - Shutdown (3.8.1.2) Decay Time (3.9.3) Crane Travel - Spent Fuel Storage Pool Building (3.9.7) Storage Pool Water Level (3.9.11) Fuel Pool Ventilation System - Fuel Storage (3.9.12) Spent Fuel Cask Crane (3.9.13) Decay Time - Storage Pool (3.9.14) Fuel Storage Criticality (5.6.1.a and 5.6.1.b) Fuel Storage Drainage (5.6.2) Fuel Storage Capacity (5.6.3)	Limiting Value or Condition: Specifies required A.C. power during movement of irradiated fuel or crane operation with loads over the SFP ≥72 hours prior to fuel movement Loads >2000 lbs shall not be moved over irradiated fuel assemblies in the storage pool Maintain ≥23 feet water over fuel seated in the storage racks One fuel pool ventilation system operable whenever irradiated fuel is in the spent fuel pool Maximum load handled by cask crane shall be ≤25 tons Irradiated fuel assemblies shall have decayed ≥1180 hours or ≥1490 hours prior to movement of cask into cask compartment Maintain k_{eff} ≤0.95, describes nominal storage pitch, pool boron concentration >1720 ppm, boraflex installed in Region 1 and Region 2 storage racks; specifies fuel assembly enrichment/exposure limits for storage in Region 1 and Region 2 Fuel pool can not be drained below elevation 56 feet Storage capacity is ≤1706 fuel assemblies
SFP Structure	Location: Above grade in fuel handling building (FHB). Fuel pool floor elevation is 21.5'; cask area floor elevation is 18.0' (8770-G-074 Rev. 10) Gross SFP Volume: 47008 ft³ (including cask storage area) to 60' normal water level. Derived from drawings 8770-4965 Rev. 1 & 8770-G-074 Rev. 10.	Seismic Classification of SFP Structure and Building: FHB & SFP designed as a seismic Class I structure (UFSAR 3.8.1.1.2); Spent fuel racks designed to seismic Category I requirements (UFSAR 9.1.2.2.3) SFP Temperature for Stress Analysis: Normal Operating Thermal loads analyzed with 150° F water at wall and 32° F external air temperature; Accident conditions used bulk water temperature of 217° F with external air temperature of 40° F. Both analyses assumed linear thermal gradients. (PSL1 rerack license amendment, Safety Analysis Report, June 12, 1987, pages 4-9 & 4-10)
Leakage Collection	Liner Type: Stainless Steel type 304; fuel pool floor 0.25" plate, liner walls 0.188" plate, cask pit floor 1.0" plate. (8770-4965 Rev 1 + FSAR page 9.1-4a)	Leakage Monitoring: Network of stainless steel angles attached to the outside of the pool liner walls and the underside of the pool liner floor (8770-G-830 sh.2, Rev 2 & 8770-G-894 Rev 5).
Drainage Prevention	Location of Bottom Drains: None. (8770-G-830 sheet 4, Rev. 1, 8770-G-830 sheet 1, Rev. 4, and sheet 2, Rev. 2)	Elevation of Gate Bottom Relative to Stored Fuel: Gate bottom is at elevation 36.25' (8770-G-830 sh. 2). This is above the top of fuel seated in the racks.

Siphon Prevention	Lowest Elevation of Connected Piping Relative to Fuel: Above top of fuel. Fuel pool cooling suction line penatrates pool liner at elevation 56.0'; return line penatrates pool liner at elevation 59.25' (8770-G-830 sheet 1). Fuel pool purification system piping penatrates fuel pool liner at an elevation of 56.0' and 59.0' (8770-G-830 sheet 2) Top of fuel assembly seated in storage racks is ~35.0'.	Anti-Siphon Devices: Fuel pool return line has 0.5" hole and purification suction line has 0.25" hole placed 1' below normal water level. (8770-G-078, sheet 140, Rev. 9)
Make-up Capability	Safety-Related Source: Intake cooling water. Normal Source: RWT or PWT depending on fuel pool boron concentration (OP 1-0350020 Rev. 21, page 11).	Seismic Classification and Quality Group: Intake cooling water makeup capability is Seismic Category I group C. (8770-G-082, sh. 1, Rev 43)
Reactivity	Limits on k_{eff} and Enrichment: For both fuel pool regions $k_{eff} \leq 0.95$ with the pool flooded with unborated water. Fresh fuel limited to ≤4.5 w/o; Region 2 has additional restrictions based on T.S. Figure 5.6-1	Soluble Boron Credit for Accidents: Yes, assembly misload (PSL1 rerack license amendment, Safety Analysis Report, June 12, 1987, pages 3-2 & 5-8).
Reactivity Control	Solid Neutron Poisons: Boraflex sheets placed between storage cells in both Region 1 and 2.	Number of Fuel Storage Zones: Two based on assembly burnup and initial enrichment.
Shared or Split Spent Fuel Pools	No. of SFPs: One	No. of SFPs Receiving Discharge from a Single Unit: One; all Unit 1 fuel is in Unit 1 pool.
SFP Design Inventory Cases	Normal: 1520 assemblies (PLA submittal to support PSL1 fuel pool rerack, pages 3-28 & 3-31, June 12, 1987).	Emergency/Abnormal: 1657 assemblies (PLA submittal to support PSL1 rerack, pages 3-28 & 3-31, June 12, 1987)
SFP Design Heat Load (MBTU/hr) and Temperature (°F)	Normal: 16.42E6; 133.3° F with 1 fuel pool cooling pump. (PLA submittal to support PSL1 fuel pool rerack, page 3-33, June 12, 1987)	Emergency/Abnormal: 33.71E6; 150.8° F with 2 fuel pool cooling pumps; 167° F with 1 pump in operation (Safety Eval. by NRR related to License Amendment 91, March 11, 1988)
SFP Cooling System	No. of Trains: 2 pumps in parallel; 1 heat heat exchanger. No. of SFPs Served by Each Train: one (8770-G-078, sh. 140, Rev 9)	Licensed to Withstand Single Active Component Failure: Yes. See section 5.2.1, Heat Removal Capability, from SER issued by NRC office of NRR related to Amendment 91 to Unit 1, dated March 11,1988.
Electrical Supply to SFP Cooling System Pumps	Qualification and Independence of Power Supply: SFP Cooling pump 1A is a load on the essential portion of 480V motor control center 1A-8. SFP Cooling pump 1B is a load on the essential section of motor control center 1B-8. These MCC's are not class 1E. (8770-G-275 sheet 8, Rev. 8)	Load Shed Initiators: Undervoltage or overcurrent. (8770-G-275 sheet 1, Rev. 12, & sheet 8, Rev. 8)
Backup SFP Cooling	System Name: None.	Qualification: N/A.

SFP Heat Exchanger Cooling Water (8770-G-083, sheet 1, Rev. 42)	System Name: Component Cooling Water	Qualification: Some portions of CCW important to SFP cooling are seismic I safety class C; others are safety class D.
Secondary Cooling Water Loop (8770-G-082, sheet 1, Rev. 43)	System Name: Intake Cooling Water	Qualification: Seismic I safety class C
Ultimate Heat Sink (UHS)	Type: Atlantic Ocean/Big Mud Creek	UHS Design Temperature: 95° F (UFSAR p. 9.2-2)
SFP Cooling System Heat Exchanger Performance (Highest Capability Heat Exchanger if not identical) (8770-2017 Rev. 2)	Design Heat Capacity (BTU/hr): 32.0E6 SFP Side Flow: 1.50E6 lbm/hr SFP Temperature: 150° F SFP Cooling Loop Return Temp: 128.7° F	Type: tube and shell Cooling Water Flow: 1.78E6 lbm/hr Cooling Water Inlet Temp: 100° F Cooling Water Outlet Temp: 118°
SFP Related Con ol Room Alarms (ONOP 1-0030131, Rev. 62)	Parameter(s): Fuel Pool High/Low Level, Fuel Pool High Temperature, Fuel Pool Pump Discharge Header Pressure-Low, Fuel Pool Pumps Motor Overload, Fuel Pool Room High Temperature, Fuel Pool Exh. HVE Low Flow/Motor Overload, CCW Flow to Fuel Pool Heat Exchanger High/Low, Noble Gas Radiation Alert.	Setpoint: ± 2" from nominal level, 137.5° F, 18 psig, pump trips, 110° F, <13800 cfm, ≥3600 gpm or ≤2850 gpm, as established by Chemistry Dept.
Location of Indications	SFP Level: None	SFP Temperature: Local readout (8770-G-078, Sheet 140, Rev. 9)
SFP Cooling System Automatic Pump Trips	Parameter(s): None other than the electrical trips listed above.	Independence: Independent electrical trips for each pump. (8770-G-275, sheet 8, Rev. 8)
SFP Boiling:	Staff Acceptance of non-Seismic SFP Cooling System Based on Seismic Category I SFP Ventilation System: Fuel pool cooling system and fuel pool vent lation system are not seismic category I. (8770-G-879 Rev. 29 & 8770-G-125 Sh. FS-W-3)	Off-site Consequences of SFP Boiling Evaluated: Yes. (L-87-537, December 23, 1987, Attachment 6) If Yes, Was Filtration Credited: No.
SFP/Reactor System Separation	Separation of SFP Operating Floor from Portion of Aux. or Reactor Bldg. that contains Reactor Safety Systems: SFP area completely enclosed; ventilation system directs air to FHB stack	Separation of Units at Multi-Unit Sites: St. Lucie Units 1 & 2 have separate fuel handling buildings and ventilation systems.
Heavy Load Handling	SFP Area Crane Qualified to Single Failure Proof Standard IAW NUREG-0612 and/or NUREG-0554: No. (PSAR Tables 9.1-6 and 9.6-1)	Routine Spent Fuel Assembly Transfer to ISFSI or Alternate Wet Storage Location: No

Operating Practices	Administrative Control Limit(s) for SFP Temperature during Refueling: None based on most recent Rev. to fuel shuffle procedure. Frequency of Full-Core Off-loads: ≤50% of outages Type of Off-load Performed during most recent refueling: partial core off-load (fuel shuffle)	Administrative Control Limits for SFP Cooling System Redundancy and SFP Make-up System Redundancy: OP 1-1600023, Rev. 58, page 9, requires Fuel Pool Cooling & Purification System to be in normal operation prior to beginning refueling evolution. This means that electric power required to be available to both fuel pool cooling pumps (OP 1-0350020, Rev. 21, page 2 & 3). No requirements for redundancy of makeup source. Administrative Controls on Irradiated Fuel Decay Time prior to Transfer from Reactor Vessel to SFP: Yes. (OP 1-1600023, Rev. 58, page 20 of 50, <u>Surviellances Performed During Refueling</u>) For Units with planned refueling outages scheduled to begin before April 30, 1996, type of Off-load planned for next refueling and planned shutdown date: Full core; expected shutdown 4/29/96.

SLSFP

SPENT FUEL STORAGE DATA TABLE

Facility	Name: St. Lucie	Unit Number: Unit 2
Licensee's SFP Contact	Name: M. P. Sharp	Telephone: (407) 694-3340
SFP Related Technical Specifications	Parameters:	Limiting Value or Condition:
	A. C. Sources - Shutdown (3.8.1.2)	Specifies required A.C. power during movement of irradiated fuel or crane operation with loads over the fuel storage pool.
	Decay Time (3.9.3)	Reactor subcritical ≥72 hours prior to fuel movement in RPV.
	Crane Travel - Spent Fuel Storage Pool Building (3.9.7)	Loads >1600 lbs prohibited from travel over fuel assemblies in fuel storage pool.
	Water Level - Spent Fuel Storage Pool (3.9.11)	Maintain ≥23 feet water over top of irradiated fuel seated in storage racks.
	Spent Fuel Cask Crane (3.9.12)	Maximum load handled by cask crane shall be ≤100 tons.
	Fuel Storage Criticality (5.6.1.a)	Maintain k_{eff} ≤0.95, specifies nominal pitch of assemblies in storage racks, requires pool boron concentration ≥1720 ppm, defines Region I and Region II enrichment/burnup requirements for storage.
	Fuel Storage Drainage (5.6.2)	SFP shall not be drained below elevation 56 feet.
	Fuel Storage Capacity (5.6.3)	SFP shall contain ≤1076 assemblies.
SFP Structure	Location: Above grade in fuel handling building (FHB). Fuel pool floor elevation is 21.50'; cask area floor elevation is 17.5'. (2998-G-073 Rev. 16 & 2998-G-074 Rev. 12) Gross SFP Volume: 52609 ft³ (including cask storage area) to 60' normal water level. (2998-6564 Rev. 3 & 2998-G-074 Rev. 12)	Seismic Classification of SFP Structure and Building: FHB & SFP designed as seismic Class I structure (UFSAR 3.8.4.1.3 & 2998-G-078 sheet 140, Rev. 5). Spent fuel racks designed to seismic Category I requirements (UFSAR 9.1.2.1) SFP Temperature for Stress Analysis: SFP designed for a water temperature of 212° F during the winter. (UFSAR p. 9.1-5a)
Leakage Collection	Liner Type: 304 Stainless steel (UFSAR p. 9.1-4); pool liner walls 0.188" plate, pool floor liner 0.625". Cask area floor plate 1.0", cask area wall plate 0.5". (2998-G-830 sheet 1, 2998-6951 Rev. 3, 2998-6952 Rev. 4, & 2998-6953 Rev. 3)	Leakage Monitoring: Network of stainless steel angles attached to the outside of the pool liner walls and underside of the pool liner floor. (2998-G-894 Rev. 9)
Drainage Prevention	Location of Bottom Drains: None. (2998-G-830 sheet 1, Rev. 7)	Elevation of Gate Bottom Relative to Stored Fuel: Above top of stored fuel. Gate bottom elevation is 36.25' (2998-6951 Rev. 3). Unit 2 fuel assemblies are 158.5" long. Top of fuel seated in the storage racks is elevation ~35.2'. (2998-18511 Rev. 0)

Siphon Prevention	Lowest Elevation of Connected Piping Relative to Fuel: Above top of fuel. Fuel pool cooling suction line penetrates pool liner at elevation 56.0' (2998-6953 Rev. 3); return line penetrates fuel pool liner at elevation 59.25' (2998-6952 Rev. 4). Fuel pool purification system piping penetrates fuel pool liner at an elevation of 56.0' and 59.0' (2998-6951 Rev. 3 & 2998-7415 Rev.2). Top of fuel storage racks is ~36.25'.	Anti-Siphon Devices: Fuel pool cooling return line has 0.5" hole placed 1.0' below the normal pool water level. Fuel pool purification suction line has a 0.25" siphon breaker hole placed 1.21' below the normal pool water level. (2998-G-078 sheet 140, Rev. 5)
Make-up Capability	Safety-Related Source: Intake cooling water Normal Source: RWT or PWT depending on fuel pool boron concentration. (OP 2-0350020 Rev. 17, page 10)	Seismic Classification and Quality Group: Intake cooling water makeup capability is Seismic category I group C. (2998-G-082 sheet 2, Rev. 40)
Reactivity	Limits on k_{eff} and Enrichment: For both fuel pool regions $k_{eff} \leq 0.95$ with the pool flooded with unborated water. Fresh fuel limited to ≤4.5 w/o; Region II has additional restrictions based on T.S. Figure 5.6-1.	Soluble Boron Credit for Accidents: Yes. (Safety Evaluation prepared by NRR for PSL2 rerack license amendment, Section 2.1.3)
Reactivity Control	Solid Neutron Poisons: No. Region I cells contain unpoisoned SS L-shaped inserts. Racks use flux trap design.	Number of Fuel Storage Zones: Two based on assembly burnup and initial enrichment.
Shared or Split Spent Fuel Pools	No. of SFPs: One	No. of SFPs Receiving Discharge from a Single Unit: One; all Unit 2 fuel is in Unit 2 pool.
SFP Design Inventory Cases	Normal: 984 assemblies (12 refueling batches) with the most recent refueling batch cooled for 5 days; other batches discharged following an 18 month fuel cycle. (CE letter L-CE-10558, September 7, 1984)	Emergency/Abnormal: 1113 assemblies comprising 11 refueling batches, each of which was discharged following an 18 month fuel cycle and a full core offload of 217 assemblies which has cooled for 7 days. (L-CE-10558)
SFP Design Heat Load (MBTU/hr) and Temperature (°F) (from Safety Evaluation by Office of NRR supporting rerack of the St. Lucie Unit 2 fuel pool, October 16, 1984)	Normal: 16.9E6 BTU/hr; <137° F with one pump in operation.	Emergency/Abnormal: 31.7E6 BTU/hr; <150° F with both spent fuel pumps operating.

SFP Cooling System	No. of Trains: 2 pumps and 2 heat exchangers. Either pump can serve either heat exchanger. No. of SFPs Served by Each Train: One (2998-G-078 sheet 140, Rev. 5)	Licensed to Withstand Single Active Component Failure: Not explicitly mentioned in rerack Safety Evaluation prepared by NRR to support fuel pool rerack, issued October 16,1984. FPL's rerack PLA submittal presented results of both normal and abnormal core offloads assuming a single failure. Earlier SE's (NUREG-0843, p. 9-5) give 160° F as expected temp. following a full core offload with 1 fuel pool cooling pump in operation.
Electrical Supply to SFP Cooling System Pumps	Qualification and Independence of Power Supply: SFP Cooling pump 2A is a load on the essential portion of 480V motor control center 2A-8. SFP Cooling pump 2B is a load on the essential portion of motor control center 2B-8. Fuel Pool Cooling system is Class IE.	Load Shed Initiators: Undervoltage or overcurrent. (2998-G-275 sheet 39, Rev. 3, sheet 42, Rev.4 & 2998-G-275 sheet A, Rev. 5 + 2998-G-274 Rev. 12 & 2998-G-274 sheet 2, Rev. 5)
Backup SFP Cooling	System Name: None.	Qualificatio.. N/A
SFP Heat Exchanger Cooling Water (2998-G-083 Sh.1, Rev. 31)	System Name: Component Cooling Water	Qualification: Seismic I safety class C
Secondary Cooling Water Loop (2998-G-082 Sh. 2, Rev. 40)	System Name: Intake Cooling Water	Qualification: Seismic I safety class C
Ultimate Heat Sink (UHS)	Type: Atlantic Ocean/Big Mud Creek	UHS Design Temperature: 95° F (UFSAR p. 9.2-1a)
SFP Cooling System Heat Exchanger Performance (Highest Capability Heat Exchanger if not identical) (2998-15609, Rev.0)	Design Heat Capacity (BTU/hr): 32.0E6 SFP Side Flow: 1.50E6 lbm/hr SFP Temperature: 150° F SFP Cooling Loop Return Temp: 128.7° F	Type: tube and shell Cooling Water Flow: 1.78E6 lbm/hr Cooling Water Inlet Temp: 100° F Cooling Water Outlet Temp: 118° F
SFP Related Control Room Alarms (ONOP 2-0030131, Rev. 50)	Parameter(s): Fuel Pool Pump Discharge Header Pressure Lo, Fuel Pool Pump Overload, Hi/Lo CCW Flow to Fuel Pool Heat Exchanger, Fuel Pool Room Temp. Hi, Fuel Pool Exhaust fans Lo Flow/Overload, Fuel Pool High/Low Level or High Temp (2 annunc. channels)	Setpoint: 18 psig, N/A, ≥3700 gpm or ≤2850 gpm, 110° F, 0.08" wg or 1130 scfm, ≥136° F or ≥6" deviation in pool water level from nominal value (2 channels).
Location of Indications	SFP Level: Local scale	SFP Temperature: Local readout (2998-G-078 sheet 140, Rev. 5 and 2998-G-078 sheet 100)
SFP Cooling System Automatic Pump Trips	Parameter(s): None other than the electrical trips listed above.	Independence: Independent electrical trips for each pump. (2998-G-275 sheet 23, Rev. 4, sheet 39, Rev. 3, and sheet 42, Rev. 4)

SFP Boiling:	Staff Acceptance of non-Seismic SFP Cooling System Based on Seismic Category I SFP Ventilation System: Fuel Pool Cooling System is Seismic Category I. (2998-G-078 sheet 140, Rev. 5) Portions of th Fuel Pool Ventilation System are Seismic Class I, safety clas (2998-G-878 Rev. 22 and 2998-G-879 sheet 3, Rev. 20)	Off-site Consequences of SFP Boiling Evaluated: No. . Yes, Was Filtration Credited:
SFP/Reactor System Separation	Separation of SFP Operating Floor from Portion of Aux. or Reactor Bldg. that contains Reactor Safety Systems: SFP area completely enclosed; ventilation system directs air to FHB stack.	Separation of Units at Multi-Unit Sites: St. Lucie Units 1 & 2 have separate fuel handling buildings and ventilation systems.
Heavy Load Handling	SFP Area Crane Qualified to Single Failure Proof Standard IAW NUREG-0612 and/or NUREG-0554: No. (FLO-2998-751 and FSAR section 9.1.4.3.2)	Routine Spent Fuel Assembly Transfer to ISFSI or Alternate Wet Storage Location: No
Operating Practices	Administrative Control Limit(s) for SFP Temperature during Refueling: Yes, ensure fuel pool temperature ≤150° F. (OP 2-1600023 Rev. 39, page 26) Frequency of Full-Core Off-loads: ≤50% of outages Type of Off-load Performed during most recent refueling: full core offload	Administrative Control Limits for SFP Cooling System Redundancy and SFP Make-up System Redundancy: OP 2-1600023 Rev. 39, pages 25 & 26 requires that both fuel pool cooling pumps and related systems be available. Makeup source from the RWT to the fuel pool is also required to be available. Administrative Controls on Irradiated Fuel Decay Time prior to Transfer from Reactor Vessel to SFP: Yes. (Page 19 of OP 2-1600023 Rev. 39) For Units with planned refueling outages scheduled to begin before April 30, 1996, type of Off-load planned for next refueling and planned shutdown date: N/A; next Unit 2 refueling outage tentatively scheduled for 4/97.

SPENT FUEL POOL CURRENT LICENSING BASES REVIEW REPORT
ST. LUCIE UNITS 1 AND 2

To verify that St. Lucie 1 and 2 comply with the current licensing bases (CLB) regarding the spent fuel pool (SFP), the Project Manager conducted an audit on March 26 and 27, 1996. The results of the audit are presented below.

St. Lucie 1

SUMMARY OF CLB REQUIREMENTS RE:SPENT FUEL POOL DECAY HEAT REMOVAL/REFUELING OFFLOAD PRACTICES AND VERIFICATIONS

1. Technical Specification limits are provided for:

   TS 3.9.3: 72 hour minimum decay time.
   Verification: Incorporated in operating procedure OP 1-1600023, Rev. 58, page 20 of 50, Step 2E

   TS 3.9.5: Direct communications between the control room and the refueling station during core alterations.
   Verification: Incorporated in OP 1-1600023, Rev. 58, page 20 of 50, Step 2D

   TS 3.9.6: Manipulator crane shall be used to move fuel assemblies and be operable.
   Verification: This requirement is for the pressure vessel, not for the SFP.

   TS 3.9.7: Crane travel with heavy loads (>2000 lbs.) over irradiated fuel is prohibited.
   Verification: Incorporated in OP 2-1600023, Rev. 58, page 15 of 50

   TS 3.9.11: Minimum water level 23 feet above the top of irradiated fuel in the SFP.
   Verification: Incorporated in OP 2-1600023, Rev. 58, page 20 of 50, Step 2C

   TS 3.9.12: At least one fuel pool ventilation system shall be operable.
   Verification: Incorporated in OP 1-0350030, Rev. 8, page 8 of 12, Step 7.2.5C

   TS 3.9.13: Maximum load for the spent fuel cask crane shall not exceed 25 tons.
   Verification: No procedure, however, St. Lucie has never used the crane.

   TS 3.9.14: Decay fuel assemblies for 1180 hours (1490 hours for >one-third core) prior to movement of the spent fuel cask into the fuel cask compartment.
   Verification: This requirement relates to the cask operation.

2. The fuel pool system is designed to provide shielding for irradiated fuel so that personnel dose rates do not exceed 2.5 mrem/hr; maintain pool temperature below 150 °F under offload conditions; maintain purity

and clarity of the SFP, refueling cavity, and refueling water tank water; and maintain water level 9 feet above the irradiated fuel during transfer operations.
Verification:
-The 2.5 mrem/hr is assured by maintaining water level a minimum of 9 feet above the irradiated fuel -

-Maintaining temperature below 150 degrees F - the licensee committed to have a procedure in place before the outage to read like the Unit 2 procedure. The relevant Unit 2 procedure is OP 2-1600023, Rev. 58, page 26 of 69.

-Maintaining purity and clarity of the SFP follows the Scheduling Procedure C-01, Rev 42, page 7 of 9. Also the Performance Procedure C-61, Rev 7, page 1 - 4 of 4.

-Minimum cover of 9 feet is assured by physical configuration and sizes of equipment. The actual minimum cover is 9'- 8". Project Manager verified this by examining the actual equipment and the design drawings.

3. Design heat load for the normal batch discharge case assumes 18 batches of 80 assemblies discharge to the SFP in 18 month intervals, followed by a discharge of 80 assemblies after 150 hours of decay. With a single pump and heat exchanger in operation, the system can maintain SFP temperature below 134 °F. Time-to-boil assuming cooling was completely lost at the maximum temperature is 13.43 hours. A full capacity pump is available should the first pump fail. [FSAR Section 9.1.3.2] Normal discharge heatload is 16.42 x 10^6 Btu/hr. [Staff rerack safety evaluation dated 3/11/88]
Verification: **the licensee could not produce a copy of the original calculations, but committed to perform a new set of calculations.**

Does the licensee consider the failure of the fuel pool heat exchanger credible. Having a single heat exchanger does not provide for single failure (this component is passive).
Verification: **The licensee does not consider the failure of the heat exchanger credible. Some years ago, the heat exchanger was taken out of service for maintenance. During that time the licensee installed and operated a temporary heat exchanger.**

The FSAR describes the normal batch discharge case as a one-third offload. In March the licensee plans to offload a full core. Is it and abnormal offload or do they "normally" off load a full core. If so, change the FSAR.
Verification: **Normal offload is 1/3 core. During the upcoming outage (starting on 4/29/96) Unit 1 will off-load full core to perform reactor vessel weld examination.**

4. Design heat load for the abnormal batch discharge case assumes 18 batches of 80 assemblies discharge to the SFP in 18 month intervals, followed by a discharge of 217 assemblies with 169 hour of decay. With both pumps and a single heat exchanger in operation, the system can maintain SFP temperature below 151 °F. Time-to-boil assuming cooling

was completely lost at the maximum temperature is 5.04 hours. The capability to withstand a single failure criteria was not assumed [FSAR Section 9.1.3.2]. The heat load for the abnormal case is 33.70 x 10^6 Btu/hr. [Staff rerack safety evaluation dated 3/11/88]
Verification: The Project Manager reviewed the calculations in support of the above temperatures.
The staff also accepted a single failure of the SFPCS pump with a full core in the SFP. The maximum temperature reached 167 °F under these assumptions. [Staff rerack safety evaluation dated 3/11/88]

The licensee's FSAR does not describe this scenario (full core offload - single failure). The licensee should be questioned whether a SFPCS single failure under full core offload heatload is part of their licensing basis.
Verification: The scenario is described in the SER for Amendment #91 (rerack amendment), Section 5.2.1, Heat Removal Capability.

5. The storage capacity for Unit 1 SFP is 1706 fuel assemblies (7 2/3 cores).
Verification: At the time of the audit, Unit 1 had 964 assemblies in the SFP. Unit 1 will reach 1700 assemblies in the year 2006.

6. Boron concentration shall be maintained at a minimum of 1720 ppm.
Verification: The licensee could not produce a procedure assuring that figure, but committed to have one in place prior to the upcoming outage.

7. The spent fuel pool is designed to withstand the steady state water temperatures of 217 °F.
Verification: The Licensee produced a set of calculations showing 5% safety margin for the most limiting condition using 217 degrees F.

8. Makeup sources to the SFP are from: refueling water storage tank, city water storage tank, city water storage tanks via portable fire pump, and the primary water tank. A seismic Category I source is available from the intake cooling water inter-tie (salt) at 150 gpm [FSAR 9.1.3.4.5].
Verification: Refueling Water Tank is used when boron concentration is less than 2100 ppm. Primary Water Tank is used when boron concentration is greater than 2100 ppm. OP 1-0350020, Rev. 21, page 11 of 25, steps 8.5.1 and 8.5.2.

Lining up seismic makeup using the refueling water tank is complicated. The PM should review the procedure to ensure it exists and that the licensee trains on it periodically.
Verification: Seismic makeup to SFP is from ICW not RWT. Lining up is not complicated and is included in the licensee training. Off-Normal Operating Procedure ONOP 1-0350030, Rev. 8, page 8 of 12.

9. No other implicit or explicit prohibitions exist within the CLB against performing a full core offload for any given refueling outage.
Verification: That is a correct statement.

Discrepancies:

None. However, see comments in each section above.
Verification: All comments have been addressed.

B. SUMMARY OF CLB REQUIREMENTS RE:SPENT FUEL POOL DECAY HEAT REMOVAL/REFUELING OFFLOAD PRACTICES AND VERIFICATIONS

1. Technical Specification limits are provided for:

TS 3.9.3: 72 hour minimum decay time.
Verification: OP 2-1600023, page 19 of 69

TS 3.9.5: Direct communications between the control room and the refueling station during core alterations.
Verification: OP 2-1600023, page 19 of 69

TS 3.9.6: Manipulator crane shall be used to move fuel assemblies and be operable.
Verification: This TS pertains to the pressure vessel, not SFP.

TS 3.9.7: Crane travel with heavy loads (>1600 lbs.) over irradiated fuel is prohibited.
Verification: OP 2-1600023, page 15 of 69

TS 3.9.11: Minimum water level 23 feet above the top of irradiated fuel in the SFP. **Verification: OP 2-1600023, page 18 of 69**

TS 3.9.13: Maximum load for the spent fuel cask crane shall not exceed 100 tons.
Verification: No procedure. FPL is not using the crane.

TS 3.9.14: Decay fuel assemblies for 1180 hours (1490 hours for >one-third core) prior to movement of the spent fuel cask into the fuel cask compartment.
Verification: Unit 2 does not have TS 3.9.14. This is Unit 1 TS.

The PM should ask why there isn't a fuel building ventilation TS similar to Unit 1 TS 3.9.12.
Verification: They do have it under Shield Building Ventilation System, TS 3/4 6.6.1; two independent trains. OP 2-1600023, page 26 of 69

2. The fuel pool system is designed to provide shielding for irradiated fuel so that personnel dose rates do not exceed 2.5 mrem/hr; maintain pool temperature below 150 °F under offload conditions; maintain purity and clarity of the SFP, refueling cavity, and refueling water tank water; and maintain water level 9 feet above the irradiated fuel during transfer operations.
Verification:
-The 2.5 mrem/hr is assured by maintaining water level a minimum of 9 feet above the irradiated fuel

-Maintaining temperature below 150 degrees F - the licensee committed to have a procedure in place before the outage to read like the Unit 2 procedure. The relevant Unit 2 procedure is OP 2-1600023, Rev. 58, page 26 of 69.

-Maintaining purity and clarity of the SFP follows the Scheduling Procedure C-01, Rev 42,

page 7 of 9. Also the Performance Procedure C-61, Rev 7, page 1 - 4 of 4.

-Minimum cover of 9 feet is assured by physical configuration and sizes of equipment. The actual minimum cover is 9'- 8". Project Manager verified this by examining the actual equipment and the design drawings.

3. Design heat load for the normal batch discharge case assumes 11 batches of 80 assemblies discharge to the SFP in 18 month intervals, followed by a discharge of 80 assemblies after 120 hours of decay. With a single pump and heat exchanger in operation, the system can maintain SFP temperature below 131 °F with a CCW temperature of 100 °F. Time-to-boil assuming cooling was completely lost at the maximum temperature is 12.6 hours. A full capacity pump is available should the first pump fail. [FSAR Section 9.1.3.1] Normal discharge heatload is 16.42 x 10^6 Btu/hr.
Verification: Project Manager reviewed the calculations and confirmed the design figures.

4. Design heat load for the full core discharge case assumes 11 batches of 80 assemblies discharge to the SFP in 18 month intervals (the most recent has decayed 90 days), followed by a discharge of 217 assemblies with 168 hours of decay. With both pumps and a single heat exchanger in operation, the system can maintain SFP temperature below 148 °F with a CCW temperature of 100 °F. Time-to-boil assuming cooling was completely lost at the maximum temperature is 3.9 hours. The capability to withstand a single failure criteria was not assumed. The heat load for the abnormal case is 30.3 x 10^6 Btu/hr [FSAR Section 9.1.3.1]. A single failure was analyzed for this heat load case. The maximum pool temperature under full core offload heatload was found to be less than 160 °F [FSAR 9.1.3.3].
Verification: Project Manager reviewed the calculations and confirmed the design figures.

5. Piping and components in the SFPCS are Quality Group C, seismic Category I, designed for a temperature of at least 200 °F. [FSAR Section 9.1.3.2.1, and Table 9.1-6.]
Verification: Project Manager reviewed the calculations and confirmed the design figures.

6. Normal makeup sources to the SFP are from the refueling water storage tank and the primary water tank. Three million gallons of makeup are also available from the city water storage tanks, condensate storage tank, demineralized water tank, and others. A seismic Category I source is also available through hoses from the intake cooling water header. [FSAR Section 9.1.3.3.1]
Verification: Refueling Water Tank is used when boron concentration is less than 2100 ppm. Primary Water Tank is used when boron concentration is greater than 2100 ppm. OP 2-0350020, Rev 17, page 10 of 19, steps 8.4.1 and 8.4.2. Also Drawing 2998-G-082, Rev. 40, Sheet 2

7. No implicit or explicit prohibitions exist within the CLB against performing a full core offload for any given refueling outage.
Verification: That is a correct statement.

Discrepancies:

None

SLSR0296.R1

REGION II

ATLANTA, GEORGIA

PLANT STATUS REPORT

ST. LUCIE

Units 1 and 2

February, 1996

ff/21

9703120429 17pp

PLANT STATUS REPORT FOR ST. LUCIE

TABLE OF CONTENTS

PART 1 - FACILITY DESCRIPTION

1.1 FACILITY/LICENSEE

FACILITY: St. Lucie Units 1 and 2
PLANT LOCATION: Hutchinson Island near Port St. Lucie, Florida
LICENSEE: Florida Power and Light Co. (Corporate Office in Juno Beach, Florida)

1.2 UTILITY SENIOR MANAGEMENT

CORPORATE:

J. L. Broadhead (Jim), Chairman of the Board and CEO
J. H. Goldberg (Jerry), President, Nuclear Division

SITE:

W. H. Bohlke (Bill) - St. Lucie Plant Interim Vice President
C. L. Burton (Chris) - Services Manager
L. W. Bladow (Wes) - Nuclear Assurance Manager
R. E. Dawson (Bob) - Business Manager
D. J. Denver (Dan) - Site Engineering Manager
A. DeSoiza (Andy) - Human Resources Manager
P. L. Fincher (Pat) - Training Manager
T. G. Kreinberg (Tom) - Nuclear Materials Management Superintendent
J. Marchese (Joe) - Maintenance Manager
C. A. Pell (Ash) - Outage Manager
L. A. Rogers (Lee) - Systems and Component Engineering Manager
J. Scarola (Jim) - Plant General Manager
E. J. Weinkam III (Ed) - Licensing Manager
J. A. West (Jeff) - Operations Manager

1.3 NRC STAFF

REGION II, Atlanta, GA:

S. D. Ebneter (Stew), Regional Administrator, (404) 331-5500
L. A. Reyes (Luis), Deputy Regional Administrator (404) 331-5610
E. W. Merschoff (Ellis), Director DRP, (404) 331-5623
K. D. Landis (Kerry), Branch Chief, (404) 331-5509
L. S. Mellen (Larry), Project Engineer, (404) 331-5561
E. Lea (Edwin), Project Engineer, (404) 331-3641

SITE:

M. S. Miller (Mark), Senior Resident Inspector, (407) 464-7822
S. S. Sandin (Steve), Acting Resident Inspector, (407) 464-7822

NRR:

D. B. Matthews, Director, Project Directorate II-2, (301) 415-1490
J. A. Norris (Jan), Senior Project Manager, Project Directorate II-2, (301) 504-1483

AEOD:

S. Israel (Sandy), Reactor Operations Analysis Branch, (301) 415-7573

1.4 LICENSE INFORMATION

	Unit 1	Unit 2
Docket Nos.	50-335	50-389
License Nos.	DPR-67	NPF-16
Construction Permit Nos.	CPPR-74	CPPR-144
Construction Permit Issued	7/1/70	5/2/77
Low Power License	NA	4/83
Full Power License	3/1/76	6/10/83
Initial Criticality	4/22/76	6/2/83
1st Online	5/17/76	6/13/83
Commercial Operation	12/21/76	8/8/83

1.5 PLANT CHARACTERISTICS

Description	Units 1 and 2
Reactor Type	Combustion Engineering PWR, 2-loop
Containment Type	Freestanding Steel w/Shield Building
Power Level	830 MWe (2700 MWt)
Architect/Engineer	Ebasco
NSSS Vendor	Combustion Engineering
Constructor	Ebasco
Turbine Supplier	Westinghouse
Condenser Cooling Method	Once Through
Condenser Cooling Water	Seawater

1.6 SIGNIFICANT DESIGN INFORMATION

1.6.1 REACTOR INTEGRITY

Reactor Pressure Vessel (RPV)

With the present fuel type and management policy, Unit 1 is expected to reach a 40-year RPV life. On this unit, the fuel type and management policy have been modified to make that RPV life span possible. Presently, a program is evolving for RPV life extension beyond the projected 40 years, potentially to 60 years, via a flux reduction program. A flux reduction program has started with the addition of eight absorbers in core corner

positions, performance of vessel fluence calculations, and determination of an optimum power profile for each core load. Calculations using current methodology and uncertainty predict a significant RPV life extension, but not to 60 years.

Due to different design and construction characteristics, Unit 2 RPV life expectancy exceeds 60 years. Low leakage core designs are now used for economic reasons, however the low leakage designs provide even greater life expectancy.

Reactor Coolant Pressure Boundary

On this CE plant, ECCS-to-RCS injection points are isolated by at least two check valves and one closed MOV. High pressure safety injection (HPSI), low pressure safety injection (LPSI), and containment spray (CS) pumps' common containment sump suctions are isolated from the containment sump by one closed MOV in conjunction with a closed seismic piping system. The CS headers are isolated from containment by one closed MOV and a check valve in conjunction with a closed seismic piping system. CVCS has the normal complement of two automatic actuation isolation valves.

1.6.2 REACTOR SHUTDOWN

Reactor Protection System

The reactor protection system provides protection for the reactor fuel and its cladding by providing automatic reactor shutdowns based on input from reactor power, reactor coolant pressure, coolant temperature, coolant flow, steam generator pressure, containment pressure, turbine hydraulic fluid pressure, and, in Unit 2 only, Component Cooling Water flow to reactor coolant pumps. The RPS is a redundant, four channel system that operates on a two-out-of-four logic.

ATWS Protection

ATWS protection, outside the normal reactor protection system, is initiated via the ESF pressurizer pressure signal. It actuates by opening contactors in the output of the CEA MG sets, thereby interrupting control element assembly power at its source. This protection has been installed on both units per CE, the NSSS, recommendations.

Remote Shutdown Facilities

These facilities are located in the switchgear rooms beneath each unit's control room.

1.6.3 CORE COOLING

Feedwater System

The main feedwater pumps are motor driven with each delivering 50 percent of the flow required for full power.

Turbine Bypass/Steam Dump Capacity

Each unit has five steam bypass valves, providing 45 percent of total capacity.

Unit 1 has one atmospheric dump valve per train (two trains) and Unit 2 has two valves per train. Each unit has the capability of dumping nine percent steam flow to the atmosphere.

Auxiliary Feedwater System

There are two motor-driven pumps on each unit with 100 percent capacity per pump. There is one steam-driven pump on each unit with 200 percent capacity. Any of the three pumps can inject to either steam generator. Automatic initiation and faulted steam generator protection are provided by each unit's Auxiliary Feedwater Actuation System provided by the NSSS.

Emergency Core Cooling System

In each unit, there are two HPSI pumps and two LPSI pumps with no unit-to-unit cross-connections. One pump of each type per unit will handle a postulated LOCA. The LPSI pumps also provide decay heat removal as required when the unit is shut down.

Decay Heat Removal

As indicated above, the LPSI pumps also provide decay heat removal as required when the unit is shut down by taking suction from the RCS (hot legs), passing the fluid through the shutdown cooling heat exchangers, and returning it to the RCS (cold legs). The heat removing medium is CCW - discussed in section 1.7.6 below. Shutdown cooling flow path overpressure protection is provided by automatic isolation valves and various relief valves in the system.

1.6.4 CONTAINMENT

Pressure Control/Heat Removal

There are two containment spray pumps and four containment fan coolers available per unit to suppress pressure spikes and cool the containment. One CS pump and two fan coolers will handle a postulated LOCA. There are no unit-to-unit cross-connections. This engineered safety feature is automatically started by ESFAS.

Hydrogen Control

Post-LOCA containment hydrogen control is accomplished on each unit by two trains of hydrogen recombiners located on the operating deck inside containment. By elevating, in a controlled manner, the temperature of containment atmosphere flowing through the recombiner, the recombiner units recombine hydrogen and oxygen to form water, thus preventing the buildup of hydrogen to potentially explosive levels.

1.6.5 ELECTRICAL POWER

Offsite AC

The station switchyard is connected to the transmission system by three independent 240 KV lines that share a right of way and interconnect with FPL's grid on the mainland approximately 10 miles West of the plant site. There are two independent offsite power feeds from the station switchyard to the emergency busses.

Onsite AC

Onsite AC power is provided by four EDGs (two per unit). EDGs are independent of other plant systems except vital DC power for control of starting. A Station Blackout (SBO) cross connection is installed and tested. This cross-connection serves the emergency busses directly and reduces cross-connect time to less than 15 minutes.

DC Power

Two trains of vital batteries per unit have been routinely tested for four-hour DC load profiles. Recently, following a cell replacement, they have been tested for three-hour battery capacity instead. The battery capacity test is harsher than the load profile test and is intended to more accurately reflect expected usage. There are four normal chargers per unit with swing chargers available for service. Non-safety batteries can be cross-connected to the safety-related swing bus if needed.

Instrumentation Power

Each unit has four inverters, two powered from each vital DC train, that provide four trains of instrumentation power.

Station Blackout Resolution Status

Unit 2 is a four-hour "DC coping" plant per the original license while Unit 1 is subject to the station blackout (SBO) rule of 10 CFR 50.63 requiring additional licensee action (unit-to-unit cross-connect of 4160V bus).

1.6.6 SAFETY-RELATED COOLING WATER SYSTEMS

Intake Cooling Water (Service Water)

Intake cooling water (ICW) for each unit originates in the unit-common Intake Canal. The canal level varies with the tides since it is filled by a level difference between the Atlantic Ocean and the ICW pumps. One 16-foot and two 12-foot diameter pipes pass under the beach to connect the ocean and canal. The intake pipe ends in the Atlantic are covered by intake structures (rebuilt in 1991) intended to limit flow velocities, particularly vertical velocity, to reduce marine life entrapment. After use, ICW returns to the ocean through the Discharge Canal and under-beach pipes.

Each unit has two trains of ICW plus a swing pump that can be aligned to either train electrically and physically. The licensee has converted the deep draft ICW pumps from externally (water) lubricated to self-lubricated to increase reliability. The 100 percent (each) capacity pumps take suction from the intake canal via a canal intake structure using traveling screen debris protection. The intake canal structures adjacent to the ICW pump suctions are continuously injected with a hypochlorite solution to reduce marine growth in the associated piping and heat exchangers.

The ICW pumps move water through two trains of heat exchangers that cool component cooling water (CCW) and two trains of heat exchangers that cool main turbine cooling water. During a postulated accident, water flow isolates from the turbine cooling heat exchangers. The discharge from the heat exchangers returns via the discharge canal to the ocean.

Closed Cooling Water Systems

Each unit has two trains of Component Cooling Water (CCW). The arrangement of two pumps and a swing pump mimics the ICW system. The swing pump can be aligned to either train. The 100 percent (each) capacity pumps drive water through the CCW/ICW heat exchangers and then on to the heat loads, mainly the containment fan coolers and the shutdown cooling (decay heat) heat exchangers (which also can operate as containment spray heat exchangers). Additionally, CCW cools a variety of bearings, seals, and oil coolers for the HPSI, LPSI, and CS pumps. A non-safety-related portion of the CCW system cools reactor coolant pump seals and the spent fuel pool. This section isolates upon engineered safety features actuation.

1.6.7 SPENT FUEL STORAGE

Wet storage capability exists up to the year 2002 (Unit 2) and 2007 (Unit 1).

1.6.8 INSTRUMENT AIR SYSTEM

Instrument air compressors and driers on each unit provide all instrument air for Unit 2 and all but containment air for Unit 1. Unit 1 has instrument air compressors inside containment.

1.6.9 STEAM GENERATORS

Each unit has two large steam generators (SGs) rather than the three or four usually seen. The licensee has begun to focus on a Unit 1 SG replacement in 1998. The SGs are under construction at the B&W Canada shops and a site organization is functioning.

1.7 EMERGENCY RESPONSE FACILITIES/PREPAREDNESS

Emergency Operations Facility:	10 miles West of site, I-95/Midway Rd. Exit
Technical Support Center:	Onsite, Adjacent to Unit 1 Control Room
Operational Support Center:	Onsite, 2nd floor of North Service Building

The last annual emergency preparedness exercise was in February, 1996. This exercise was formally evaluated by the NRC.

Since St. Lucie site has a high probability of hurricanes, communications facilities were improved following the Turkey Point experience with Hurricane Andrew in August, 1992. Improvements include:

- High Frequency Auto-link with other FPL sites and NRC.
- Enhanced 900 MHZ System for site and mobile communications, with radios also in the licensee's EOF and county emergency facility.
- Cellular phones with hardened antennas.
- Hardened Local Government Radio antenna ties.

1.8 PRESENT OPERATIONAL STATUS

Availability Factors:

	Unit 1	Unit 2
1991	81.0	100.0
1992	96.5	75.2
1993	74.0	71.8
1994	86.8	79.6
1995 (through 7/95)	93.9	98.3
Cumulative (through 7/95)	77.7	83.7

1.8.1 UNIT 1 OPERATING HISTORY (Past Twelve Months from 1/25/96)

Unit 1 operated continuously during the past 12 months with the following exceptions:

On February 21, 1995, the unit was removed from service for the replacement of pressurizer code safety valves which had been leaking by the seat since shortly after startup in November, 1994. On March 4, 1995, the unit experienced a 14 minute loss of shutdown cooling. The apparent root cause was operator error by a reactor operator placing one loop of SDC in standby. The operator apparently closed the suction valve to the operating, vice standby, pump. The operator in question denied the error; however, the licensee determined that he was responsible. He resigned from the company. The unit was returned to service on March 8, 1994.

On July 8, 1995, the unit tripped during turbine valve surveillance testing. It returned to power on July 12, 1995.

On August 1, 1995, the unit was shutdown as a result of Hurricane Erin. Due to a series of equipment problems and personnel performance issues, the unit remained shut down for 73 days. Problems encountered during the shutdown included a maintenance-induced RCP seal failure, discovery of two inoperable PORVs due to maintenance errors during refurbishment, a loss of inventory event while placing shutdown cooling in service due to lack of margin to relief valve lift setpoint and complicated by an excessive blowdown value, inadvertant spraydown of the Unit 1 containment, catastrophic failure of the 1B EDG, and leaking pressurizure code safety valve flange leakage. The unit returned to power on October 12.

On November 16, the unit was manually tripped when a feedwater regulating valve failed to the 50% position, resulting in low steam generator water level. The root cause of the failure was determined to be a faulty power supply. The power supply was replaced and the unit was returned to service on November 18.

On January 22, 1996, operator error resulted in an excessive dilution event which resulted in reactor power accending to 100.2%. The operator in question apparently left the control room while dilution was in progress without informing other watchstanders of the evolution in progress. The operator was removed from licensed duties and the final disposition of the event is pending.

1.8.2 UNIT 2 OPERATING HISTORY (Past Twelve Months from 1/25/96)

Unit 2 operated continuously during the past 12 months with the following exceptions:

On February 21, 1995, the unit tripped as a result of low steam generator water level. The condition was the result of a feedwater regulating valve closure after a steam generator water level control level transmitter failed high. The transmitter was replaced and the unit was returned to service on February 25, 1995.

On April 25, 1995, the unit was shutdown for approximately 8 hours to replace a main turbine DEH power supply.

On August 1, 1995, the unit was shutdown as a result of Hurricane Erin. It was restarted on August 4, 1995, but operated at reduced power from August 17 through 29, 1995, to clean condenser water boxes and repair equipment problems.

On October 9, the unit entered a refueling outage. The outage was complicated by the discovery of leaks in RCS flow transmitter taps at the loops, a reactor flange O-ring leak, discovered during repressurization, and the failure of one stage of an RCP seal package. The unit returned to power on January 1, 1996.

The unit was manually tripped from approximately 35% power on January 5 due to high generator hydrogen temperature. The root cause of the event was improper operation of a turbine cooling water temperature control valve which supplied cooling water to the hydrogen coolers. Post-trip review resulted in the discovery of clogged steam generator water level transmitter sensing lines which resulted in artificially low levels being indicated when steam generators were isolated upon turbine trip. The lines were blown down and the unit was returned to service on January 7.

1.9 OUTAGE SCHEDULE AND STATUS

Unit 1's last refueling outage began on October 26, 1994, and ended on November 29, 1994. Major activities included: refueling; reactor vessel nozzle and flange weld ISI inspection; installation of a permanent cavity seal ring; replacing reed switches for several CEAs; integrated safeguards test; steam generator tube inspection and plugging; steam generator sludge lancing; repair of refueling water storage tank; several instances of reduced inventory/ mid-loop operations; replacement of ICW/CCW LOOP logic [HFA latching relays] with pull-to-lock switches; removal [collection] of Rx vessel neutron flux dosimetry; modification of EDG skids to allow access underneath; inspection of ECCS sump area; replacement of a main transformer; modification of containment spray NaOH addition piping; and mechanical, electrical, and I&C systems maintenance. The next Unit 1 refueling outage is scheduled for April 29, 1996.

Unit 2's last refueling outage began on October 9, 1995, and ended January 1, 1996. Major outage activities included: refueling; steam generator tube inspection and plugging; low pressure turbine blade replacement; emergency diesel generator inspection; replacement of three

reactor coolant pump mechanical seals; and mechanical, electrical, and I&C systems maintenance. The next Unit 2 refueling outage is scheduled for April 15, 1997.

PART 2 - PLANT PERSPECTIVE

2.1 GENERAL PLANT PERSPECTIVE

A SALP board meeting was conducted on January 18, 1996, covering the SALP period of January 2, 1994, through January 6, 1996. The facility was rated category 1 in the areas of Plant Support and Engineering and 2 in the areas of Operations and Mainenance and Surveillance. The latter scores were a decline from the previous SALP cycle, when the facility was rated category 1 in all areas.

2.2 SALP HISTORY (Past 2 SALP Periods)

The last SALP period, SALP Cycle 11, ended on January 6, 1996. The current SALP period ends (tentatively) in June, 1997.

ASSMT. PERIOD	OPS	RAD	MNT/SURV	EP	SEC	ENG/TECH	SAQV
5/1/89 - 10/31/90	1	1	2	1	1	1	1
11/1/90 - 5/2/92	1	1	1	1	1	1	1

	PLANT OPS	MAINTENANCE	ENGINEERING	PLANT SUPPORT
5/3/93 - 1/1/94	1	1	1	1
1/2/94 - 1/6/96	2	2	1	1

2.3 SELECTED SALP AREA DISCUSSION

Since July 1995, there has been a series of events that led to questioning the plants overall performance. These have included:

- A Unit 1 turbine trip due to procedural weakness, operator performance and supervisory oversight.
- The attempt to restage an RCP seal using inadequate and inappropriate procedural guidance. The evolution was compounded by failing to follow aspects of the guidence that did exist, which led to the failure of the second and third stage seals.

- A main steam isolation signal due to an operator failing to block the MSIS signal during a cooldown when an annunciator indicated that the block was enabled. This failure occurred dispite the fact that that the operator's attention was directed to the annunciator on at least two different occassions.

- Both pressurizer power operated relief valves being found inoperable due to incorrect assembly during a refueling outage. The conditions had existed for approximately 10 months.

- An loss of RCS inventory due to a shutdown cooling relief valve which lifted and then failed to reseat due to incorrect setpoint margins (a generic problem involving several valves). The licensee had sufficient evidence that this generic condition existed, but had failed to act promptly to evaluate the conditions.

- The spraydown of containment due to an inadequate procedure and operator error coupled with an existing operator-work-around.

These and several other recent deficiencies involving weak procedures, a general lack of procedural compliance, equipment failures, and personnel errors clearly indicated that the plant's past high level of performance had declined.

These and other problems led to several plant management changes, an overall evaluation of the recent plant problems by a plant-requested independent assessment team, and a root cause evaluation by the NRC. In a meeting with the NRC on August 29, 1995, the licensee committed to use the results of the independent assessment team to develop an action plan for improvement.

<u>Plant Operations</u>

Summary of Previous Assessment

The previous SALP assessment concluded that Operations remained strong, that management actions were aggressive in dealing with identified weaknesses, and that attention to detail was a continuing challenge for the licensee.

Summary of the Most Recent SALP

The board concluded that licensee performance had declined in the most recent SALP period. The board found that day-to-day activities were conducted with a degree of complacency. Corrective actions, management involvement and communication of expectations, attention to detail, procedural adequacy and adherence, and operator workarounds were similarly considered to be challenges to licensee performance.

Maintenance/Surveillance

Summary of Previous Assessment

Maintenance was assessed as category 1 in the previous SALP. Assessments made early in the most recent cycle indicated that the performance level of maintenance activities had not abated.

Summary of the Most Recent SALP

The board concluded that performance in this functional area had declined. Areas of concern included the existance of long-standing equipment problems and a sense that management expectations were either low or not adequately enforced. Of particular concern was the fact that equipment failure factored into 6 unit trips during the SALP cycle. Additionally, worker adherence to procedures, and the quality and adequacy of procedures was found to be a challenge to performance.

Engineering

Summary of Previous Assessment

The previous assessments for this SALP cycle concluded that engineering was generally strong. Good support of the plant was cited, as was the quality of engineering products, both to the site and in submittals to the NRC.

Summary of the Most Recent SALP

The board concluded that Engineering continued to perform at a superior level. Continued support to the plant, as well as adequacy in safety and operational evaluations were identified. In addition, the licensee's activities at the engineering materials laboratory and in the developement of maintenance specifications were seen as strengths.

PART 3 - SIGNIFICANT EVENTS

3.1 SIGNIFICANT EVENTS BRIEFINGS (Past 12 Months)

Unit 1: 95-08, 3/22/95, Failures of Rosemount Transmitters due to Gas Permeation of Monel Diaphragms

Unit 2: None

3.2 ENFORCEMENT STATUS/HISTORY (Past 12 Months)

- SL III Violation ($50,000 CP) for violations associated with inoperable Unit 1 PORVs

- Predecisional Enforcement Conference held. SL IV violation issued for failure to take prompt corrective action for issues relating to relief valve lift and blowdown setpoint values which resulted in a loss of Unit 1 RCS inventory while on shutdown cooling.

PART 4 - STAFFING AND TRAINING

4.1 OPERATIONS STAFF - OVERALL (9/95)

Average performance of the operations staff has been noted. Control room demeanor of personnel is above average.

Number of Shifts: (RCO, SRO) Five shift rotation, 8-hour shifts; (NPO, ANPO, SNPO) Five shift rotation, 8-hour shifts.

Number of SROs: 38 active/13 inactive/ 51 total
Number of ROs: 23 active/1 inactive/ 24 total
Total Licensed Operators: 61 active/14 inactive/ 75 total

4.2 WORK FORCE (2/96)

Plant personnel (including disciplines below) 787

Breakdown by Major Organization	FPL	Contractors
Operations	128	0
Chemistry	20	0
Health Physics	73	0
Maintenance	311	60
Outage Management	21	0
Nuclear Material Management	36	0
Site Engineering*	50	0
Juno Engineering		
Security	9	120
QA/QC	37	0

* Includes Reactor Engineers, System Engineers, and Test Engineers

4.3 OPERATOR QUALIFICATION/REQUALIFICATION PROGRAM (Past Two Years)

4.3.1 REQUALIFICATION PROGRAM

Last Inspection - 9/26/94. Inspection Report 50-335,389/94-19

Next Inspection - 10/96

4.3.2 INITIAL EXAMS

Last Exams 10/17/94 -	2 RO	2 passed for 100%
	9 SRO	9 passed for 100%
Next Exam 3/25/96 -	6 RO	

4.4 PLANT SIMULATOR

The simulator is on site and fully certified to meet ANSI/ANS 3.5, 1985.

4.5 INPO ACCREDITATION

All training programs are maintaining INPO accreditation. The site specific simulator has been used for training since 1988 and has been fully certified for approximately 5 years. NRC inspections in the form of operator examinations at the simulator have found no serious problems.

PART 5 - INSPECTION ACTIVITIES

5.1 INSPECTION FOLLOWUP OPEN ITEMS SUMMARY (UNITS 1 AND 2 COMBINED) (10/6/94)

Division	Pre 95	1995	Division Total	Change from Last Report
DRP	4	34	18	
DRS	10	4	14	
Total	14	37	51	

Note: Each item that applies to both units is counted as one item.

5.2 MAJOR INSPECTIONS

IR-No.	Date	Type
89-02	1/89	RG-1.97
89-03	3/89	NDE
89-07	3/89	EQ
89-09	3/89	Design Control
89-24	10/89	Maintenance Team Inspection
89-27	11/89	EOP Followup
90-09	4-5/90	OSTI
91-03	2-3/91	EDSFI
91-18	9/91	MOV (no negative findings)
91-201	9-10/91	Service Water Inspection
92-14	7/92	Emergency Preparedness Program
92-17	7/92	EDSFI Followup
93-01	1/93	Check Valves
94-11	5/94	MOV Followup
95-05	6/95	Engineering

95-16	9/95	PORV Special Inspection
96-01	1/96	Dilution Event Spectial Inspection

5.3 PLANNED TEAM INSPECTIONS

None

5.4 INFREQUENT INSPECTION PROCEDURE STATUS

No core inspection procedures are overdue at this time.

5.5 SIMS STATUS - OPEN TMI ITEMS

There are no open TMI items.

SL SR0995.WP

REGION II

ATLANTA, GEORGIA

PLANT STATUS REPORT

ST. LUCIE

SEPTEMBER, 1995

FF/27

PLANT STATUS REPORT FOR ST. LUCIE (9/95)

TABLE OF CONTENTS

****EDWIN UPDATE*****

PART 1 - FACILITY DESCRIPTION

1.1 FACILITY/LICENSEE

FACILITY: St. Lucie Units 1 and 2
PLANT LOCATION: Hutchinson Island near Port St. Lucie, Florida
LICENSEE: Florida Power and Light Co. (Corporate Office in Juno Beach, Florida)

1.2 UTILITY SENIOR MANAGEMENT

CORPORATE:

J. L. Broadhead (Jim), Chairman of the Board and CEO
J. H. Goldberg (Jerry), President, Nuclear Division

SITE:

D. A. Sager (Dave) - St. Lucie Plant Vice President
C. L. Burton (Chris) - Services Manager
L. W. Bladow (Wes) - Nuclear Assurance Manager
H. F. Buchanan (Hank) - Health Physics Supervisor
R. L. Dawson (Bob) - Licensing Manager
D. J. Denver (Dan) - Site Engineering Manager
H. L. Fagley (Herman) - Construction Services Manager
P. L. Fincher (Pat) - Training Manager
R. J. Frechette (Bob) - Chemistry Supervisor
P. Fulford (Paul) - Operations and Testing Support Supervisor
J. Marchese (Joe) - Maintenance Manager
W. L. Parks (Bill) - Reactor Engineering Supervisor
C. A. Pell (Ash) - Outage Manager
L. Rogers (Lee) - Systems and Component Engineering Manager
J. Scarola (Jim) - Plant General Manager
J. A. West (Jeff) - Operations Manager
C. H. Wood (Chuck) - Operations Supervisor

1.3 NRC STAFF

REGION II, Atlanta, GA:

S. D. Ebneter (Stew), Regional Administrator, (404) 331-5500
L. A. Reyes (Luis), Deputy Regional Administrator (404) 331-5610
B. A. Boger (Bruce), Acting Director DRP, (404) 331-5623
D. M. Verrelli (Dave), Branch Chief, (404) 331-5535
K. D. Landis (Kerry), Section Chief, (404) 331-5509
R. P. Schin (Bob), Project Engineer, (404) 331-5561
A. R. Long (Becky), Project Engineer, (404) 331-4664

SITE:

R. L. Prevatte (Dick), Senior Resident Inspector, (407) 464-7822
M. S. Miller (Mark), Resident Inspector, (407) 464-7822

NRR:

- S. A. Varga (Steven), Director, Division of Reactor Projects-I/II, (301) 504-1403
- J. A. Zwolinsky (John), Deputy Director, Division of Reactor Projects-I/II, (301) 504-1335
- D. B. Matthews, Deputy Director, Project Directorate II-2, (301) 415-1490
- J. A. Norris (Jan), Senior Project Manager, Project Directorate II-2, (301) 504-1483

AEOD:

- S. Israel (Sandy), Reactor Operations Analysis Branch, (301) 415-7573

1.4 LICENSE INFORMATION

	Unit 1	Unit 2
Docket Nos.	50-335	50-389
License Nos.	DPR-67	NPF-16
Construction Permit Nos.	CPPR-74	CPPR-144
Construction Permit Issued	7/1/70	5/2/77
Low Power License	NA	4/83
Full Power License	3/1/76	6/10/83
Initial Criticality	4/22/76	6/2/83
1st Online	5/17/76	6/13/83
Commercial Operation	12/21/76	8/8/83

1.5 PLANT CHARACTERISTICS

Description	Units 1 and 2
Reactor Type	Combustion Engineering PWR, 2-loop
Containment Type	Freestanding Steel w/Shield Building
Power Level	830 MWe (2700 MWt)
Architect/Engineer	Ebasco
NSSS Vendor	Combustion Engineering
Constructor	Ebasco
Turbine Supplier	Westinghouse
Condenser Cooling Method	Once Through
Condenser Cooling Water	Seawater

1.6 SIGNIFICANT DESIGN INFORMATION

1.6.1 REACTOR INTEGRITY

Reactor Pressure Vessel (RPV)

With the present fuel type and management policy, Unit 1 is expected to reach a 40-year RPV life. On this unit, the fuel type and management policy have been modified to make that RPV life

span possible. Presently, a program is evolving for RPV life extension beyond the projected 40 years, potentially to 60 years, via a flux reduction program. A flux reduction program has started with the addition of eight absorbers in core corner positions, performance of vessel fluence calculations, and determination of an optimum power profile for each core load. Calculations using current methodology and uncertainty predict a significant RPV life extension, but not to 60 years. Excore dosimetry installed for the current cycle [with planned removal in October, 1994] will be used to reduce calculation uncertainty.

Due to different design and construction characteristics, Unit 2 RPV life expectancy exceeds 60 years. Low leakage core designs are now used for economic reasons, however the low leakage designs provide even greater life expectancy.

Reactor Coolant Pressure Boundary

On this CE plant, ECCS-to-RCS injection points are isolated by at least two check valves and one closed MOV. High pressure safety injection (HPSI), low pressure safety injection (LPSI), and containment spray (CS) pumps' common containment sump suctions are isolated from the containment sump by one closed MOV in conjunction with a closed seismic piping system. The CS headers are isolated from containment by one closed MOV and a check valve in conjunction with a closed seismic piping system. CVCS has the normal complement of two automatic actuation isolation valves.

1.6.2 REACTOR SHUTDOWN

Reactor Protection System

The reactor protection system provides protection for the reactor fuel and its cladding by providing automatic reactor shutdowns (8 trips) based on input from reactor power, reactor coolant pressure, coolant temperature, coolant flow, steam generator pressure, and containment pressure. The RPS is a redundant four-channel system that operates on a two-out-of-four logic.

ATWS Protection

ATWS protection, outside the normal reactor protection system, is initiated via the ESF pressurizer pressure signal. It actuates by opening contactors in the output of the CEA MG sets, thereby interrupting control element assembly power at its source. This protection has been installed on both units per CE, the NSSS, recommendations.

Remote Shutdown Facilities

These facilities are located in the switchgear rooms beneath each unit's control room.

1.6.3 CORE COOLING

Feedwater System

The main feedwater pumps are motor driven with each delivering 50 percent of the flow required for full power.

Turbine Bypass/Steam Dump Capacity

Each unit has five steam bypass valves, providing 45 percent of total capacity.

Unit 1 has one atmospheric dump valve per train (two trains) and Unit 2 has two valves per train. Each unit has the capability of dumping nine percent steam flow to the atmosphere.

Auxiliary Feedwater System

There are two motor-driven pumps on each unit with 100 percent capacity per pump. There is one steam-driven pump on each unit with 200 percent capacity. Any of the three pumps can inject to either steam generator. Automatic initiation and faulted steam generator protection are provided by each unit's Auxiliary Feedwater Actuation System provided by the NSSS.

Emergency Core Cooling System

In each unit, there are two HPSI pumps and two LPSI pumps with no unit-to-unit cross-connections. One pump of each type per unit will handle a postulated LOCA. The LPSI pumps also provide decay heat removal as required when the unit is shut down.

Decay Heat Removal

As indicated above, the LPSI pumps also provide decay heat removal as required when the unit is shut down by taking suction from the RCS (hot legs), passing the fluid through the shutdown cooling heat exchangers, and returning it to the RCS (cold legs). The heat removing medium is CCW - discussed in section 1.7.6 below. Shutdown cooling flow path overpressure protection is provided by automatic isolation valves and various relief valves in the system.

1.6.4 CONTAINMENT

Pressure Control/Heat Removal

There are two containment spray pumps and four containment fan coolers available per unit to suppress pressure spikes and cool the containment. One CS pump and two fan coolers will handle a postulated LOCA. There are no unit-to-unit cross-connections. This engineered safety feature is automatically started by ESFAS.

Hydrogen Control

Containment hydrogen control post-LOCA is accomplished on each unit by two trains of hydrogen recombiners located on the operating deck inside containment. By elevating, in a controlled manner, the temperature of containment atmosphere flowing through the recombiner, the recombiner units recombine hydrogen and oxygen to form water, thus preventing the buildup of hydrogen to potentially explosive levels.

1.6.5 ELECTRICAL POWER

Offsite AC

The station switchyard is connected to the transmission system by three independent 240 KV lines that share a right of way and interconnect with FPL's grid on the mainland approximately 10 miles West of the plant site. There are two independent offsite power feeds from the station switchyard to the emergency busses.

Onsite AC

Onsite AC power is provided by four EDGs (two per unit). EDGs are independent of other plant systems except vital DC power for control of starting. A Station Blackout (SBO) cross connection is installed and tested. This cross-connection serves the emergency busses directly and reduces cross-connect time to less than 15 minutes.

DC Power

Two trains of vital batteries per unit have been routinely tested for four-hour DC load profiles. Recently, due to cell replacement, they have been tested for three-hour battery capacity instead. The battery capacity test is harsher than the load profile test. There are four normal chargers per unit with swing chargers available for service. Non-safety batteries can be cross-connected to the safety-related swing bus if needed.

Instrumentation Power

Each unit has four inverters, two powered from each vital DC train, that provide four trains of instrumentation power.

Station Blackout Resolution Status

Unit 2 is a four-hour "DC coping" plant per the original license while Unit 1 is subject to the station blackout (SBO) rule of 10 CFR 50.63 requiring additional licensee action (unit-to-unit cross-connect of 4160V bus).

1.6.6 SAFETY-RELATED COOLING WATER SYSTEMS

Intake Cooling Water (Service Water)

Intake cooling water (ICW) for each unit originates in a common canal called the Intake Canal. The canal level varies with the tides since it is filled by a level difference between the Atlantic Ocean and the canal. One 16-foot and two 12-foot diameter pipes pass under the beach to connect the ocean and canal. The intake pipe ends in the Atlantic are covered by intake structures (rebuilt in 1991) intended to limit flow velocities, particularly vertical velocity, to reduce marine life entrapment. After use, ICW returns to the ocean through a Discharge Canal and under-beach pipes.

Each unit has two trains of ICW plus a swing pump that can be aligned to either train electrically and physically. The licensee has converted the deep draft ICW pumps from externally (water) lubricated to self-lubricated to increase reliability of the lubrication water source. The 100 percent (each) capacity pumps take suction from the intake canal via a canal intake structure using traveling screen debris protection. The intake canal structures adjacent to the ICW pump suctions are continuously injected with a hypochlorite solution to reduce marine growth in the associated piping and heat exchangers. Commencing 3/92, periodic injection of a clamicide at the intake structures, primarily to control marine growth affecting the turbine condensers, has also somewhat reduced marine growth affecting the ICW system.

The ICW pumps move water through two trains of heat exchangers that cool component cooling water (CCW) and two trains of heat exchangers that cool main turbine cooling water. During a postulated accident, water flow isolates from the turbine cooling heat exchangers. The discharge from the heat exchangers returns via the discharge canal to the ocean.

Increases in debris and silt in the heat exchangers during 1993 indicated that the intake canal needed dredging.

- As of September 1993, the utility was routinely cleaning main condenser waterboxes at reduced power and obtaining necessary dredging permits from the state and Corps of Engineers.

- The canal was dredged in December 1993 and January 1994 with immediate results of reduced waterbox fouling.

Closed Cooling Water Systems

Each unit has two trains of Component Cooling Water (CCW). The arrangement of two pumps and a swing pump mimics the ICW system.

The swing pump can be aligned to either train. The 100 percent (each) capacity pumps drive water through the CCW/ICW heat exchangers and then on to the heat loads, mainly the containment fan coolers and the shutdown cooling (decay heat) heat exchangers (which also can operate as containment spray heat exchangers). Additionally, CCW cools a variety of bearings, seals, and oil coolers for the HPSI, LPSI, and CS pumps. A non-safety-related portion of the CCW system cools reactor coolant pump seals and the spent fuel pool. This section isolates upon engineered safety features actuation.

1.6.7 SPENT FUEL STORAGE

Wet storage capability exists up to the year 2002 (Unit 2) and 2007 (Unit 1).

1.6.8 INSTRUMENT AIR SYSTEM

Instrument air compressors and driers, installed several years ago on each unit, provide all instrument air for Unit 2 and all but containment air for Unit 1. These have increased instrument air reliability. Unit 1 also has instrument air compressors inside containment.

1.6.9 STEAM GENERATORS

Each unit has two large steam generators (SGs) rather than the three or four usually seen. The licensee has begun to focus on a Unit 1 SG replacement in 1997. The SGs are under construction at the B&W Canada shops and a site organization is functioning.

1.7 EMERGENCY RESPONSE FACILITIES/PREPAREDNESS

Emergency Operations Facility:	10 miles West of site, I-95/Midway Rd. Exit
Technical Support Center:	Onsite, Adjacent to Unit 1 Control Room
Operational Support Center:	Onsite, 2nd floor of North Service Building

The last annual emergency preparedness exercise was in May, 1995. This exercise was not formally evaluated by the NRC. The next emergency preparedness exercise is scheduled for February, 1996.

Since St. Lucie site has a high probability of hurricanes, communications facilities were improved following the Turkey Point experience with Hurricane Andrew in August, 1992. Improvements include:

- High Frequency Auto-link with other FPL sites and NRC.

- Enhanced 900 MHZ System for site and mobile communications, with radios also in the licensee's EOF and county emergency facility.

- Cellular phones with hardened antennas.

- Hardened Local Government Radio antenna ties.

1.8 PRESENT OPERATIONAL STATUS (3/9/95)

Unit 1 has been operating at full power since _____. The unit was shutdown on August 1 as a result of Hurricane Erin. A series of problems including RCP seal failure, both PORVs inoperable due to incorrect assembly, SDC relief valve problems, associated problems with several other relief valves, inadvertent spraydown of the containment, catastrophic failure of 1B emergency diesel generator, and a leaking flange on a pressurizer safety valve resulted in the unit being shutdown for _____ days. While the unit was down, a large number of operator-work-arounds and other plant deficiencies were corrected. The next refueling outage is scheduled for April 4, 1996.

Unit 2 was shutdown on April 25 for approximately seven hours to replace a main turbine digital electro hydraulic power supply. The unit was down power for several days in June and July to clean condenser water boxes. The unit was shutdown on August 1 as a result of Hurricane Erin. It restarted on August 4. Power was reduced from August 17 through 29 to clean condenser water boxes and repair various secondary plant deficiencies. The next refueling outage is scheduled for October 9, 1995.

Availability Factors:

	Unit 1	Unit 2
1991	81.0	100.0
1992	96.5	75.2
1993	74.0	71.8
1994	86.8	79.6
1995 (through 7/95)	93.9	98.3
Cumulative (through 1/95)	77.7	83.7

1.8.1 UNIT 1 OPERATING HISTORY (Past Twelve Months from 8/1/94)

Unit 1 operated continuously during the past 12 months with the following exceptions:

Unit 1 reduced power and entered mode 2 on August 28 to repair a DEH leak. The unit was returned to power approximately 18 hours later on the same date.

On October 26, 1994, the unit tripped from 100 percent power due to a loss of electrical load. This was the result of arc-over in a potential transformer in the switchyard due to salt buildup. The licensee then entered a unit refueling outage, which had been scheduled to begin four days later. The unit was returned to service on November 29.

On February 21, 1995, the unit was removed from service for the replacement of pressurizer code safety valves which had been leaking by the seat since shortly after startup in November, 1994. The unit was returned to service on March 8.

On March 4, 1995, the unit experienced a 14 minute loss of shutdown cooling. The apparent root cause was operator error by a reactor operator placing one loop of SDC in standby. The operator apparently closed the suction valve to the operating, vice standby, pump. The operator in question has denied the error. The licensee is considering disciplinary action and has relieved the operator of licensed activities.

On June 11, 1995, the unit was down powered to 40 percent to jumper out a cell on 1B safety related battery.

On July 8, 1995, the unit tripped during turbine valve surveillance testing. It returned to power on July 12.

On August 1, 1995, the unit was shutdown as a result of Hurricane Erin. Due to a series of equipment problems and personnel performance issues, the unit was not restarted until _____.

1.8.2 UNIT 2 OPERATING HISTORY (Past Twelve Months from 8/1/95)

Unit 2 operated continuously during the past 12 months with the following exceptions:

On February 21, 1995, the unit tripped as a result of low steam generator water level. The condition was the result of a feedwater regulating valve closure after a steam generator water level control level transmitter failed high. The transmitter was replaced and the unit was returned to service on February 25.

On April 25, 1995, the unit was shutdown for approximately 8 hours to replace a main turbine DEH power supply.

On August 1, 1995, the unit was shutdown as a result of Hurricane Erin. It was restarted on August 4 but operated at reduced power from August 17 through 29 to clean condenser water boxes and repair equipment problems.

1.9 OUTAGE SCHEDULE AND STATUS

Unit 1's last refueling outage began on October 26, 1994, and ended on November 29, 1994. Major activities included: refueling; reactor vessel nozzle and flange weld ISI inspection; installation of a permanent cavity seal ring; replacing reed switches for several CEAs; integrated safeguards test; steam generator tube inspection and plugging; steam generator sludge lancing; repair of refueling water storage tank; several instances of reduced inventory/ mid-loop operations; replacement of ICW/CCW LOOP logic [HFA latching relays] with pull-to-lock switches;

removal [collection] of Rx vessel neutron flux dosimetry; modification of EDG skids to allow access underneath; inspection of ECCS sump area; replacement of a main transformer; modification of containment spray NaOH addition piping; and mechanical, electrical, and I&C systems maintenance.

Unit 2's last refueling outage began on February 13, 1994, and ended April 17, 1994. Major outage activities included: refueling; steam generator tube inspection and plugging; low pressure turbine blading replacement; emergency diesel generator inspection; replacement of two reactor coolant pump mechanical seals; and mechanical, electrical, and I&C systems maintenance. The next Unit 2 refueling outage is scheduled for October, 1995.

PART 2 - PLANT PERSPECTIVE

2.1 GENERAL PLANT PERSPECTIVE

A SALP presentation was conducted on February 15, 1994, covering the SALP period of May 3, 1992, through January 1, 1994. The facility was rated category 1 in all functional areas for the second consecutive SALP period.

In June 1994, St Lucie was dropped from the NRC management list of good performers after experiencing five unit reactor trips in the first half of 1994.

2.2 SALP HISTORY (Past 2 SALP Periods)

The last SALP period, SALP Cycle 10, ended on January 1, 1994. The current SALP period ends on July 1, 1995.

ASSMT. PERIOD	OPS	RAD	MNT/SURV	EP	SEC	ENG/TECH	SAQV
5/1/89 - 10/31/90	1	1	2	1	1	1	1
11/1/90 - 5/2/92	1	1	1	1	1	1	1

	PLANT OPS	MAINTENANCE	ENGINEERING	PLANT SUPPORT
5/3/93 - 1/1/94	1	1	1	1

2.3 SELECTED SALP AREA DISCUSSIONS (9/1/95)

Since July 1995, there has been a series of events that led to questioning the plants overall performance. These have included: a Unit 1 turbine trip due to procedural weakness, operator performance and

supervisory oversight; the attempt to restage an RCP seal using inadequate and inappropriate procedural guidance which led to the failure of the second and third stage seals, a main steam isolation signal due to inappropriate operator response, an inadvertent reactor protection system actuation due to inattention to detail by an operator, both pressurizer relief valves being inoperable due to incorrect assembly during a refueling outage, an inoperable shutdown cooling relief valve due to incorrect setpoint margins (a generic problem involving several valves), the spray down of containment due to an inadequate procedure and operator error coupled with an existing operator-work-around. These and several other recent deficiencies involving weak procedures, a general lack of procedural compliance, equipment failures, and personnel errors clearly indicate that the plants past high level of performance has declined. Both units were shutdown on August 1 for Hurricane Erin. Unit 2 immediately restarted but Unit 1 remained shutdown for ______ days due to the above problems. The above problems have led to several plant management changes, an overall evaluation of the recent plant problems by a plant requested independent assessment team and a root cause evaluation by the NRC. In a meeting with the NRC on August 29, the licensee committed to use the results of the independent assessment team to develop an action plan for improvement.

Plant Operations

Summary of Previous Assessment

Within the current SALP cycle, previous assessments have noted a *potential* decline in Operations' performance. Noted indicators included five reactor trips in the first six months of the cycle. No common root causes were identified. Operator actions with regard to the noted trips were generally good. Two entries into reduced inventory operations during the Unit 2 outage were noted as excellent. Procedural weaknesses which indicated a lack of rigor in the review process were noted, as was the fact that temporary changes to procedures were on the increase (indicating increasing attention to procedural adequacy).

Management activities in response to the increase in operational events was determined to be strong, with an increase in overall focus directed at plant operations. The corrective actions program was enhanced, consolidating tens of programs into one which involves daily management reviews of all documented conditions.

The previous assessments concluded that Operations remained strong in the current period, that management actions were aggressive in dealing with identified weaknesses, and that increased attention to procedural adequacy may be warranted.

Last Six Months

The previous six months has shown an increase in personnel errors involving, the failure to follow procedures, inattention to detail, the failure to maintain awareness of equipment status, and weaknesses in logkeeping. Only one reactor trip, a turbine trip due to operator error, occurred during this time span. Operator response to that event was excellent. Overall response to plant startups, shutdown, power maneuvers has been good. Several findings indicated weaknesses in personnel performance, procedural adequacy, inattention to detail, weak logkeeping, equipment failures, poor communications, and living with operator-work-arounds. They include:

- Overpressurizing the main generator
- Not logging equipment out of service
- Starting a LPSI pump with the suction valve closed
- Overfilling PWT
- Spray down of Unit 1 Containment
- Improper staging of RCP seal resulted in seal failure
- Failure to block MSIS actuation
- Turbine trip due to operator error
- STAR/NCR not evaluating past operability
- Temporary modification not shown on CR drawing
- Loss of SDC, operator closed suction isolation valve
- Weak annunciator response on loss of SDC
- Operator failed to identify level out of sight on EDG cooling water tank
- Spent fuel pool housekeeping
- Failure of SGWL Rosemount transmitter (maintenance)
- 2B LPSI pump found airbound
- Failure to sample SIT within TS required time frame following volume addition (second occurrence in 2 years)
- Failure to identify and analyze hot leg flow stratification

Strengths

Strengths have been identified in operator response to trips, transients, and power maneuvers. Post job or evaluation briefings have overall been timely and thorough with the exception of several recent events.

Weaknesses

See paragraph 1 above.

Conclusion

Operations performance has declined in the past six months. Operators respond well to events but do not always have a questioning attitude, appear to have lapses in procedural use and compliance, and are not identifying and forcing plant support organizations to correct plant deficiencies.

Logkeeping and attention to detail have led to an increase in errors.

Maintenance/Surveillance

Summary of Previous Assessment

Maintenance was assessed as category 1 in the previous SALP. The previous assessments made during the current SALP cycle indicated that the performance level of maintenance activities had not abated. Strong performance had been noted in the support of the Unit 2 outage, and housekeeping and plant preservation activities were deemed good.

Last Six Months

During the past six months, 24 maintenance activities were observed in varying levels of depth. One violation involving the installation of incorrect size motor overload heater was identified. Three potential violations involving inadequate surveillance, inadequate post maintenance tests, and two inoperable PORV are currently being evaluated. Two non-cited violations involving inadequate control on jumpers were identified. Workers were found to be well skilled and trained overall. Problems have been noted in procedural adequacy and use.

Twenty-two surveillance activities were observed. Two non-cited violations involving the failure to perform surveillance within specified time limits were identified. These were the result of a weak surveillance tracking system.

Strengths

The licensee continues to use and improve on their online maintenance procedure and implementation. Overall maintenance activities performed under this program were well planned and executed. The craft work force is motivated and overall skill level is high. The licensee has completed the development of their maintenance rule and it will be in place and operating by the end of September. The predictive maintenance organization continues to provide early indication of pending failure and assists in root cause evaluation of equipment failures.

Weaknesses

Weaknesses have been identified in the following areas:

- Procedural adequacy
- Procedural compliance
- Installation of incorrect parts
- Personnel errors in work performance
- Surveillance tracking system
- Equipment failures
- Control of lifted leads/jumpers
- Communications

Conclusion

Maintenance performance has declined. Equipment failures have impacted plant operation. Craft personnel are not identifying and correcting procedural deficiencies and are using procedures as general guidance. Individual and group performance is generally excellent to high visibility jobs, but attention to detail appears to lapse on routine work.

Engineering

Summary of Previous Assessment

The previous assessments for this SALP cycle concluded that engineering was generally strong. Good support of the Unit 2 outage was noted, as was good QA with respect to fuel fabrication and receipt inspection. Potential problems were noted in the area of vendor technical manuals.

Last Six Months

The noted concerns with respect to VTMs were, in part, validated in the maintenance area, where a violation resulted; however, the violation was not reflective of a failure on the part of engineering. Good support to the Unit 1 outage was noted, with engineering personnel assuming pivotal roles in the management of the outage. One NCV was identified, relating to the design of NaOH supply piping, however, the problem had existed since shortly after construction and was appropriately addressed.

Five plant modifications and several safety evaluations were reviewed and were generally found to be thorough and correct. The licensee's program for the control of containment coatings was reviewed and found to be satisfactory. Engineering involvement has been evident in each major plant challenge in the last six months, including:

- Apparent air-binding of the 2B LPSI pump
- 1A LPSI pump relief valve lift
- Unit 1 Pressurizer relief valve seat leakage
- Post-event reviews of loss of Unit 1 SDC

- Unit 1 RWT leak repairs

Conclusion

Engineering continues to perform well. No weaknesses have been identified in this functional area.

Plant Support

Radiological Controls

Previous assessments this SALP cycle indicated an effective program. Inspections this period indicate good control of internal/external exposure and containment during outages. ALARA initiatives were noted; robotics, submersibles, and telemetry. The licensee was noted to be ahead of most of the region in the use of cameras, video and wireless communications.

Emergency Preparedness

The licensee continues to maintain an effective EP program.

Security

Security upgrades made prior to the last SALP were notable. The licensee continues to maintain a very effective security program.

Fire Protection

The licensee continues to maintain an effective fire protection program.

Housekeeping

Housekeeping has been generally very good.

PART 3 - SIGNIFICANT EVENTS

3.1 SIGNIFICANT EVENTS BRIEFINGS (Past 12 Months)

Unit 1: None this period

Unit 2: Failure of a GE AK-25 Trip Circuit Breaker

3.2 ENFORCEMENT STATUS/HISTORY (Past 12 Months)

Currently, there are no escalated enforcement actions pending at St. Lucie.

PART 4 - STAFFING AND TRAINING

4.1 OPERATIONS STAFF - OVERALL (9/95)

Average performance of the operations staff has been noted. Control room demeanor of personnel is above average.

Number of Shifts:	(RCO, SRO) Five shift rotation, 8-hour shifts; (NPO, ANPO, SNPO) Five shift rotation, 8-hour shifts.
Number of SROs:	38 active/13 inactive/ 51 total
Number of ROs:	23 active/1 inactive/ 24 total
Total Licensed Operators:	61 active/14 inactive/ 75 total

4.2 WORK FORCE (8/94)

	FPL	Contractor
Plant personnel (excluding disciplines below)	699	122
Training	64	0
Quality Assurance/ISEG/SPEAKOUT	39	0
Materials Management	47	0
Security	11	122
Site Engineering	48	0

4.3 OPERATOR QUALIFICATION/REQUALIFICATION PROGRAM (Past Two Years)

4.3.1 REQUALIFICATION PROGRAM

NRC-administered requalification exams were completed in October, 1992. Results were good - 9 of 12 RO's passed and 12 of 12 SRO's passed. Three of the RO's failed the written exam and one also failed the JPMs. The program was rated satisfactory. Requalification exams are currently in progress (10/94). To date, 20 of 24 SRO's and 17 of 20 RO's have passed all portions of the exams. Failures have included 5 written exams, 1 JPM, and 1 simulator failure.

4.3.2 INITIAL EXAMS

Previous initial operator exams were conducted on April 29, 1991. Six SRO upgrades were examined, and all six passed. Additional exams were completed October 25, 1991. Six operators, 2 SRO upgrades, and 1 instant SRO were examined. All passed. The last initial exam was given April 27 through May 1, 1992, to 6 SRO upgrades and 2 ROs, and all passed. A hot license class of 15 persons was started in late February, 1992 (14 still in class).

The last initial exam was conducted in October 1993 - 10 of 10 prospective ROs passed. Initial exams are planned for October, 1994, with 3 ROs and 7 SRO Upgrades planned

4.3.3 GENERIC FUNDAMENTAL EXAM

On an NRC administered Generic Fundamental Exam on June 6, 1990, 6 of the 10 St. Lucie operators who took the exam passed. On February 6, 1991, 3 of 3 operators who took the exam passed. On June 6, 1991, one operator took the exam and passed. On February 10, 1993, all 12 operators who took the exam passed. One person took the exam on February 9, 1994, and passed. No further Generic Fundamental Exams have been taken.

4.4 PLANT SIMULATOR

The simulator is on site and fully certified to meet ANSI/ANS 3.5, 1985.

4.5 INPO ACCREDITATION

All training programs are maintaining INPO accreditation. The site specific simulator has been used for training since 1988 and has been fully certified for approximately 4 years. Eight separate NRC inspections in the form of operator examinations at the simulator have found no serious problems.

PART 5 - INSPECTION ACTIVITIES

5.1 INSPECTION FOLLOWUP OPEN ITEMS SUMMARY (UNITS 1 AND 2 COMBINED) (10/6/94)

Division	Pre 93	Total	Change from Last Report
DRP	3	30	0
DRS	0	7	-3
DRSS	0	2	0
Totals	3	39	-3

Note: Each item that applies to both units is counted as one item.

5.2 MAJOR INSPECTIONS

IR-No.	Date	Type
89-02	1/89	RG-1.97
89-03	3/89	NDE
89-07	3/89	EQ
89-09	3/89	Design Control

89-24	10/89	Maintenance Team Inspection
89-27	11/89	EOP Followup
90-09	4-5/90	OSTI
91-03	2-3/91	EDSFI
91-18	9/91	MOV (no negative findings)
91-201	9-10/91	Service Water Inspection
92-14	7/92	Emergency Preparedness Program
92-17	7/92	EDSFI Followup
93-01	1/93	Check Valves
94-11	5/94	MOV Followup

5.3 PLANNED TEAM INSPECTIONS

None

5.4 INFREQUENT INSPECTION PROCEDURE STATUS

No core modules are overdue at this time.

5.5 SIMS STATUS - OPEN TMI ITEMS

There are no open TMI items.

ATTACHMENT 3

NRR OPERATING REACTOR ASSESSMENT

NRR ASSESSMENT FOR ST. LUCIE

October 1994

CURRENT ISSUES

-Seismic qualification of electrical and mechanical equipment (GL 87-02, USI A-46) issue on Unit 1 is still not resolved. The staff issued a letter in early 1994 providing a general framework of criteria which would resolve this issue. FPL responded in May 1994 restating their previous position and stating that they believe that further NRC requests for work, evaluations, or plant changes would provide no additional safety benefit to their nuclear facilities. The staff is considering performing a backfit analysis to determine the possibility of ordering FPL to implement additional actions or accept the licensees position. A third alternative being evaluated is performance of a site inspection to determine if any safety-significant issues exist in the areas of disagreement.

-Unit 1 will be replacing steam generators in 1997. The licensee is well into planning for the event.

-An alternative approach to the resolution of the Thermo-Lag issue was proposed by FPL, however, the staff did not pursue review of this performance based approach based on Commission direction of this issue. The licensee is scheduled to submit to the staff by early November 1994 a schedule and method for resolution of the Thermo-Lag issue.

-The plant continues to perform well. The latest SALP evaluation had ratings of 1 in all categories.

Contact:

Jan A. Norris
504-1483

August 28, 1995

FILE WITH
IE 95-14
MGM

MEMORANDUM TO: John A. Zwolinski, Deputy Director
Division of Reactor Projects I/II, ...

FROM: Ellis W. Merschoff, Director
Division of Reactor Projects

SUBJECT: REQUEST FOR ASSISTANCE IN ADDRESSING ISSUES REGARDING ST. LUCIE EMERGENCY DIESEL GENERATOR FUEL OIL TRANSFER SYSTEM LEAK ISOLATION AND USING OPERATOR ACTION IN PLACE OF AUTOMATIC ACTION (TIA 95-013)

Recently, the 2B Emergency Diesel Generator (EDG) fuel oil (FO) transfer system developed a leak at St. Lucie Unit 2. The licensee's actions in response to this event included isolating the leak to minimize environmental contamination. The licensee performed this action under the provisions of 10 CFR 50.59. The licensee's actions in this regard have given rise to generic questions involving the relationship between PRA evaluations and 10 CFR 50.59 requirements. The background on the issue and specific questions arising from it are detailed below.

System Description

The St. Lucie EDGFO transfer system (for a given train) consists of a FO tank, a transfer pump, a day tank mounted on each of two EDG engines (two engines per EDG unit), and associated piping and valves. The transfer scheme involves the pumping of FO from the storage tank, via the transfer pump, through piping from the FO building to the EDG building and then to the day tanks. The day tanks' contents are then pumped directly to the EDG engines.

The piping from the transfer pump discharge to the day tank is normally unisolated with the exception of normally closed solenoid valves at the day tanks. When the EDG is running, FO is drawn from each day tank until low level signals open the solenoids, allowing a gravity feed of FO from the FO tank to the day tanks. Should level continue to fall, low-low level conditions in the day tanks initiate a start signal to the transfer pump to increase the makeup rate.

Condition Description

Over the course of several days, the licensee noted a decrease in 2B EDGFO inventory and suspected that a leak had developed. Through increased monitoring, the licensee determined the leak to be in the piping between the FO transfer pump and the day tanks. As the piping was below grade, rapid identification and correction of the leak was impossible.

To terminate the release of approximately 15 gallons per day of FO to the environment through the leak, the licensee proposed operating with an

ff/31

9606040260-XA 12pp

isolation valve at the discharge of the FO transfer pump closed (the valve is normally locked open). As a compensatory measure, the licensee proposed dedicating a non-licensed operator to the task of responding to open the valve should the EDG start. The operator would have no concurrent event response role (e.g. fire brigade); however, he would have non-response duties to perform during the course of a shift. Additionally, the licensee proposed revising a number of procedures to include the requirement of opening the valve in the event of an EDG start.

Safety Evaluation

The licensee elected to perform the actions described above under the auspices of 10 CFR 50.59. The Safety Evaluation (SE) performed pursuant to the code noted that two new failure modes were created by the proposed action. The first involved a failure of the operator to arrive at and open the subject valve prior to the associated EDG's day tanks emptying. The second involved a mechanical failure that precluded the opening of the valve.

The licensee performed a PRA study of the proposed change which indicated that an approximately 6 per cent increase existed in the estimated frequency (per year) of the loss of the EDG and the associated safety bus. The SE went on to state that procedures would be revised, operators trained, overall awareness heightened, and, as a result, no net increase in the probability of failure of a component important to safety would result from the proposed change.

Questions

In light of the licensee's conclusions, we propose the following questions:

1. Is the attached 10 CFR 50.59 FPL Safety Evaluation (JPN-PSL-SENS-95-013) considered acceptable?

2. From a PRA perspective, is it possible to completely mitigate a risk, once introduced?

3. Is the licensee's position (that the risk of operator failure/error can be mitigated, probabilistically, through procedures and training) valid? Do probabilistic estimations of operator error rates presuppose the existence of procedures and training and, if so, can one then take credit for them in a deterministic mitigation of risk?

4. Can 10 CFR 50.59 requirements (that the probability of failure of components important to safety not be increased if no unreviewed safety question is deemed to exist) be satisfied if new failure mechanisms are added to a previously reviewed system?

5. PRA insights are beginning to provide a more structured evaluation process for proposed changes to facilities and, as a result, are showing that changes (in a 10 CFR 50.59 context) present finite, although small, increases in the probabilities of failures. Is there a threshold value of increased probability (representing "negligible" or "insignificant" increases) below which 10 CFR 50.59 criteria (for demonstrating that

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unreviewed safety questions do not exist) are satisfied?

6. The response to a related TIA from Region III, transmitted via letter from you to Edward Greenman dated June 23, 1993, stated in part that "NRR has no particular objection to the use of PRA in 10 CFR 50.59 evaluations but recommends that it play a supportive role, in conjunction with other inputs, such as engineering judgement and operating experience." In the given case at St. Lucie, when PRA insights provide information counter to (as opposed to supportive to) the 10 CFR 50.59 conclusions, is it appropriate to accept deterministic conclusions over the PRA-indicated increase in probabilities of failure?

This request has been discussed with J. Norris of the NRR staff. If you have any questions concerning this request, please contact M. Miller (407/464-7822) or K. Landis (404/331-5509).

Docket No. 50-335/389
License No. DPR-67/NPF-16

Attachments: 1. FPL Safety Evaluation JPN-PSL-SENS-95-013
2. NRC IR 50-335, 389/95-14

cc w/atts:
R. Cooper, RI
W. Axelson, RIII
J. Dyer, RIV
K. Perkins, WCFO
S. Vias, RII
J. Norris, NRR

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REVIEW AND APPROVAL RECORD

PLANT ST LUCIE UNIT 2

TITLE 10CFR50.59 EVALUATION OPERATION WITH DIESEL OIL TRANSFER PUMP 2B DISCHARGE ISOLATION VALVE V17216 CLOSED

LEAD DISCIPLINE LICENSING

ENGINEERING ORGANIZATION NUCLEAR ENGINEERING DEPT.

REVIEW/APPROVAL:

GROUP	INTERFACE TYPE			PREPARED	VERIFIED	APPROVED	FPL APPROVED*
	INPUT	REVIEW	N/A				
MECH	XX			[illegible]	[illegible]	[illegible]	
ELECT			XX				
I&C			XX				
CIVIL			XX				
LIC**	XX			cgWaig	[illegible]	cgWaig	
CSI			XX				
NUC FUEL			XX				
PRA	XX			MH Vincent	MH Vincent	MH Vincent	

[illegible] FOR C.W. GREY PER TELECON

* Per Contractor Evals As Determined By Projects   ** Review Interface As A Min On All 10CFR50.59 Evals and PLAs

FPL PROJECTS APPROVAL: AHWest DATE: 7/6/95

OTHER INTERFACES:

NONE

ATTACHMENT 1

ST. LUCIE PLANT - UNIT NO. 2
10CFR50.59 EVALUATION FOR OPERATION WITH DIESEL OIL TRANSFER PUMP 2B DISCHARGE ISOLATION VALVE V17216 CLOSED

1.0 ABSTRACT

This safety evaluation is to document the acceptability of plant operation with Diesel Oil Transfer Pump (DOTP) 2B discharge isolation valve V17216 in the CLOSED position. Compensatory measures shall be established to open the valve upon operation of the 2B Emergency Diesel Generator (EDG). V17216 is normally a LOCKED OPEN valve; however, due to a suspected leak in the underground piping downstream of the valve it is desired to isolate the piping until the leak is identified and repairs are made or the line has been replaced. Isolation of the line will prevent the loss of an estimated 15 gallons per day of diesel fuel oil to the environment.

Valve V17216 is located in line I-2"-DO-14 which connects the DOTPs to the 2B EDG Day Tanks. This line is classified as safety class three (3), seismic class I; therefore, this evaluation is classified as Safety Related.

This evaluation concludes that operation of the plant with valve V17216 in the CLOSED position does not impact plant safety and does not constitute an unreviewed safety question nor require a change to the technical specifications. This conclusion is contingent upon implementation of the following operating restrictions and compensatory actions:

- operating personnel shall be instructed to open valve V17216 as soon as possible and within 20 minutes of any unplanned starting of the 2B EDG;
- prior to closing V17216 and at least twice each shift, verify that the 2B EDG day tanks are each filled to $\geq$ 320 gallons (93% full per local level indication);
- valve V17216 must be manually opened prior to any planned operation of the 2B EDG or anytime fuel oil makeup is required for the 2B EDG day tanks;
- instructions shall be provided to all appropriate plant personnel regarding the above.

This evaluation does not address system operability and plant operation during repair or replacement of the subject pipe.

.0 Description and Purpose

The underground portion of the pipeline between DOTP 2B and the day tanks for the 2B EDG is suspected of leaking at a rate of approximately 15 gallons per day. The exact location of the leakage is currently unidentified and efforts are underway to locate the leak such that the line can be repaired or replaced. The purpose of this evaluation is to allow the plant to continue operation with the DOTP 2B discharge isolation valve (V17216) in the CLOSED position, thus isolating the fuel oil leak to the environment. Compensatory actions are identified in section 9.

3.0 Licensing Requirements

Valve V17216 is part of the diesel generator fuel oil system that transfers fuel from the Diesel Oil Storage Tanks (DOSTs) to the day tanks. Per FSAR Section 9.5.4.1 the diesel fuel oil storage and transfer system is designed to perform the following functions:

a) provide oil storage capacity for at least 7 days power operation of one emergency diesel generator set;

b) maintain fuel supply to at least one diesel generator set, assuming a single active or passive failure of the system coincident with loss of offsite power;

c) meet seismic Category I and Quality Group C requirements; and

d) withstand maximum flood levels or tornado wind loadings without loss of function.

The system is broken down into two subsystems (A & B). Each subsystem consists of a DOST, a DOTP, two day tanks and associated valves, piping and instrumentation. During normal operation subsystem A serves diesel generator A and subsystem B serves diesel generator B; however, the two subsystems can be cross-connected at the discharge of the transfer pumps.

Technical specifications 3.8.1.1 and 3.8.1.2 identify the operability requirements of the diesel generators.

A similar evaluation was performed for Unit 1 in 1992 (reference 3).

4.0 Analysis of Effects on Safety

Valve V17216 is located in line I-2"-DO-14 which connects the DOTPs to the 2B EDG day tanks. This line is classified as safety class three (3), seismic class I.

Under normal operating conditions, V17216 is in a LOCKED OPEN position and provides a flow path for diesel fuel oil to the 2B EDG day tanks from the 2B DOTP and the DOST. System operation is described below.

The suction of DOTP 2B is connected to the 2B DOST via lines I-3"-DO-6 & 8 and manual valve V17212. The discharge of the 2B DOTP is connected to 2B EDG Day Tanks 2B1 and 2B2 via transfer lines I-1-1/2"-DO-12, I-2"-DO-14, I-1-1/2"-DG-260, I-1-1/2"-DG-262; check valves

V17214 & V29299; manual isolation valves V17215, V17216; and solenoid valves SE-59-1B1 & SE-59-1B2. The manual valves in the flow path from the DOST to the EDG Day Tanks are normally locked open. Solenoid valves SE-59-1B1 & SE-59-1B2 are located in the diesel generator building upstream of the day tanks and provide automatic isolation of the day tanks when the prescribed fuel oil level is obtained. Level Switches LS-59-019B & LS-59-027B start DOTP 2B and open the associated day tank solenoid valve when the day tank level decreases to 22.5" (223 gallons). Level Switches LS-59-020B & LS-59-026B stop the DOTP and close the solenoid valve when the day tank level increases to 32.5" (320 gallons). The above operation is automatic.

The system operation proposed by this safety evaluation would be the same as described above with the exception of the 2B DOTP discharge isolation valve V17216, which will be closed. Closing of valve V17216 will isolate the 2B EDG Day Tanks from the DOTP's discharge and the DOSTs. Operating personnel will be instructed to provide for the opening of valve V17216 in the event of a 2B EDG auto start.

Assuming an initial day tank fuel volume of 320 gallons, the EDG could run approximately 126 minutes at full load without replenishing the day tank. This is based on the 16 cylinder engine which is the limiting factor:

320 gallons	initial day tank fuel volume
16 gallons	unusable day tank volume (reference 4)
304 gallons	usable day tank volume
223 gallons	day tank auto fill level
2.4 gpm	maximum fuel consumption rate (based on reference 4 values)

304 gal/2.4 gpm = 126.7 minutes of operation

After approximately 40 minutes of operation, the DOTP would be automatically started as a result of a low day tank level (320 - 223 = 97 gallons fuel volume between DOTP start/stop setpoints consumed at 2.4 gpm). Plant Operations Department has indicated that an operator can respond to the starting of the 2B EDG and open valve V17216 within 20 minutes. Thus, the DOTP will not automatically start and run against shutoff head prior to the opening of V17216.

Based on a 15 gal/day leakage rate and the system configuration, the size of the suspected hole in the pipe is estimated to be less than 1/16" diameter (reference 3). The underground portion of I-2"-DO-14 is at plant elevation 13'-6" (reference 7) which is about 5' below grade. A recent study (reference 6) measured ground water levels in the vicinity of the Unit 2 EDG building at approximately 13' to 14' below grade, well below the subject pipe. Additionally, filtration is provided downstream of the day tanks. Therefore, based on the estimated size of the hole and location of the piping, the possibility of the introduction of foreign material such as sand or ground water is considered to be very small.

Operability of the subject pipe has been addressed in the reference 5 STAR. The suspected underground leak has been quantified at approximately 15 gal/day. The 2B DOTP has a design flow rate of 25 GPM (reference 1) and provides sufficient flow margin to deliver fuel to the 2B EDG to maintain the required fuel oil level in the day tanks.

A risk assessment was conducted by FPL's PSA group. This assessment used the baseline Unit 2 PSA model to estimate the change in frequency of loss of the 2B3 4.16kV bus with a loss of grid initiating event and the addition of two new 2B EDG failure modes (i.e., failure of the EDG fuel oil manual isolation valve to open and failure of the operator to open the closed isolation valve). A non-recovery probability of 3.01E-2 was used for the operator failing to open the fuel oil isolation valve. This probability was based on the ex-control model of ORCA using a 120 minute available time and a 20 minute mean response time.

Two cases were assessed:

Case 1: Baseline PSA model case

Case 2: Baseline model with the additional failure modes for the 2B EDG (manual fuel oil isolation valve failing to open and operator failing to open the valve).

The estimated frequency for each case is as follows:

Case 1: 1.73E-3/yr

Case 2: 1.84E-3/yr

This indicates that the additional failure modes resulting from the closed fuel oil isolation valve results in an approximate 6% change in the estimated frequency per year of loss of the Unit 2 2B3 4.16kV bus.

SUMMARY

Based on the above scenario, sufficient time exists for an operator to open valve V17216 prior to DOTP 2B automatically starting to replenish EDG 2B day tanks to normal levels and sufficient margin exists from the 2B DOTP to deliver the required flow rate of fuel to the 2B EDG, considering the expected ground leakage loss. Implementation of the actions required in section 9.0 will provide functional capabilities equivalent to the original configuration.

5.0 Failure Modes and Effects Analysis

FAILURE MODE	CAUSE	SYMPTOMS & EFFECTS
V17216 Fails to Open	Operator Fails to Open Valve	Loss of Fuel Supply to EDG 2B; EDG 2B Failure Due To Fuel Starvation After Approx. 2hrs; EDG 2A Available as Emergency AC Power Supply
V17216 Fails to Open	Valve Failure	Same as Above

6.0 Plant Restrictions

There are no operating restrictions (mode restrictions) on the plant while valve V17216 is maintained in the CLOSED position. This evaluation does require compensatory actions which are identified in section 9.

7.0 Effect on Technical Specifications

The proposed activity will have no effect on plant Technical Specifications. Operability of the diesel fuel oil transfer system is assured by virtue of the compensatory actions prescribed by this evaluation. Once valve V17216 is opened the fuel oil system will effectively be returned to its original design configuration and will operate in its normal automatic mode.

8.0 Unreviewed Safety Question Determination

With respect to Title 10 of the Code of Federal Regulations, Part 50.59, a proposed change shall be deemed to involve an unreviewed safety question: (i) if the probability of occurrence or the consequences of an accident or malfunction of equipment important to safety previously evaluated in the Safety Analysis Report may be increased, or (ii) if a possibility for an accident or malfunction of a different type than any evaluated previously in the Safety Analysis Report may be created, or (iii) if the margin of safety as defined in the bases for any Technical Specification is reduced. Based upon the above evaluations, it can be demonstrated that plant operation with valve V17216 in the CLOSED position to isolate the DOST from the potential pipe leak and the stated compensatory actions in place does not pose an unreviewed safety question as defined by 10CFR50.59 because each of the seven questions presented below can be appropriately answered:

1) *Does the proposed activity increase the probability of occurrence of an accident previously evaluated in the SAR?*

The proposed activity involves the B train of the EDG fuel oil system. FSAR section 15.10 describes the unit response to a station blackout event. The probability of a station blackout has not been increased since the operators are capable of assuring that valve V17216 will be opened prior to the starting of DOTP 2B. Therefore,

there is no increase in the probability of occurrence of an accident previously analyzed in the SAR.

2) *Does the proposed activity increase the consequences of an accident previously evaluated in the SAR?*

The consequences of an accident previously evaluated in the SAR have not been increased since the performance and operation of the 2B EDG will not be impacted by this change. Additionally, this change will not create a new path for uncontrolled radioactive releases and will not adversely affect any radiation monitoring equipment or equipment which is relied upon to mitigate radiological consequences of an accident.

3) *Does the proposed activity increase the probability of occurrence of a malfunction of equipment important to safety previously evaluated in the SAR?*

The proposed activity slightly alters the method for initiating fuel flow from the DOSTs to the EDG Day Tanks. Valve V17216 is normally a LOCKED OPEN valve that does not require any actuation in order to ensure a flow path from the DOSTs to the 2B EDG day tanks. This evaluation allows V17216 to be placed in the CLOSED position provided the identified compensatory actions are implemented. These compensatory actions assure the reliability of the EDG fuel oil supply. Additionally, once V17216 is opened, the fuel oil transfer system functions as originally designed.

As identified in section 5 of this evaluation, the failure of V17216 to open (due to either valve or operator failure) is possible. Such a failure would result in the loss of the 2B EDG due to fuel starvation after approximately two hours of operation. A risk assessment was conducted by FPL's PSA group to determine the change in the reliability of the B side electrical power system following implementation of the specified compensatory actions. Since the EDG System is only required to perform its safety function following a loss of offsite power to the safety electrical buses, failures of the system were taken in conjunction with a loss of offsite power.

In the proposed configuration, the change in frequency of a loss of the B side electrical power is slightly increased; however, this small increase is not considered significant when coupled with the fact that plant procedures will be modified to provide for operators who will be specially instructed to open V17216 as soon as possible and within 20 minutes after an unplanned start of the 2B EDG. Based on the above, it can be concluded that the probability of occurrence of a malfunction of equipment important to safety previously evaluated in the safety analysis report has not been increased.

4) *Does the proposed activity increase the consequences of a malfunction of equipment important to safety previously evaluated in the SAR?*

The consequences of a malfunction of equipment important to safety previously evaluated in the SAR have not been increased since the most limiting failure would result in the loss of a single EDG which is an analyzed event. No other safety systems or equipment required

for accident mitigation or radiation monitoring are impacted.

5) *Does the proposed activity create the possibility of an accident of a different type than any previously evaluated in the SAR?*

A failure modes and effects analysis has been performed for the proposed activity. This analysis (see section 5) has identified two potential failures which would result in the failure of V17216 to open. Failure of the valve to open would, after approximately two hours, result in the loss of the 2B EDG due to fuel starvation. The loss of a single EDG is an analyzed event. No other failure modes have been identified for the proposed activity. Based on the above, the possibility of an accident of a different type than any previously evaluated in the safety analysis report does not exist.

6) *Does the proposed activity create the possibility of a different type of malfunction of equipment important to safety than any previously evaluated in the SAR?*

As stated in discussions above, a failure modes and effects analysis has been performed for the proposed activity. This analysis has identified two potential failures which would result in the failure of V17216 to open. Such a failure would ultimately result in the loss of the 2B EDG, due to fuel starvation. The loss of a single EDG is an analyzed event. No other failure modes have been identified for the proposed activity. Additionally, except for the operator action to initially open V17216, the operation of the fuel oil transfer system is not impacted. No other systems are effected by the proposed activity. Based on the above, the possibility of a malfunction of equipment important to safety of a different type than any previously evaluated in the safety analysis report has not been created.

7) *Does the proposed activity reduce the margin of safety as defined in the basis for any technical specification?*

The proposed activity does not reduce the margin of safety as defined in the basis for any technical specification since the proposed activity does not impact EDG operability (Technical Specifications 3.8.1.1 and 3.8.1.2). The compensatory actions required by this evaluation ensure a reliable supply of fuel oil to the day tanks of the 2B EDG and, upon the opening of V17216, the fuel oil transfer system will function as designed.

CONCLUSION

10CFR50.59 allows changes to a facility as described in the SAR if they do not involve an unreviewed safety question or if a change in the Technical Specifications is not required. As shown in the preceding sections, the proposed change does not involve an unreviewed safety question because each concern as posed by 10CFR50.59 that pertains to unreviewed safety questions can be appropriately answered and a change to a Technical Specification is not required; therefore, prior NRC approval is not required.

9.0 Actions Required

1. Operating personnel shall be instructed to ensure that V17216 is opened as soon as possible and within 20 minutes of any unplanned starting of the 2B EDG.

2. Prior to closing V17216 and at least twice each shift, verify that the 2B EDG day tanks are each filled to ≥ 320 gallons (93% full per local level indication).

3. Valve V17216 must be manually opened prior to any planned operation of the 2B Diesel Generator or any time fuel oil makeup is required for the 2B Diesel Generator day tanks.

4. Review & revise plant procedures and conduct operator training as appropriate.

5. Restore V17216 to its normal LOCKED OPEN position as soon as practical after the completion of any leak repairs or line replacement and before the completion of the next refueling outage.

   Note: This evaluation does not address system operability and plant operation during repair or replacement of the subject pipe.

10.0 References

1) St. Lucie Unit 2 FSAR, Amendment 9
2) St. Lucie Unit 2 Technical Specifications, Amendment 75
3) JPN-PSL-SENS-92-014, Rev. 0
4) Calculation PSL-2FJM-90-025, Rev. 3
5) STAR 950712
6) Contamination Assessment Report St. Lucie Power Plant Unit 2 Emergency Generator Diesel Fuel Storage Tanks, Atlanta Testing & Engineering, September 8, 1994
7) Drawing 2998-G-174, Rev. 14
8) Drawing 2998-G-086, Sh. 1, Rev. 27
9) Drawing 2998-G-096, Sh. 2, Rev. 5

11.0 Attachments

None

UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W., SUITE 2900
ATLANTA, GEORGIA 30323-0199

August 22, 1995

Florida Power and Light Company
ATTN: Mr. J. H. Goldberg
President - Nuclear Division
P. O. Box 14000
Juno Beach, FL 33408-0420

SUBJECT: NRC INSPECTION REPORT NOS. 50-335/95-14 AND 50-389/95-14

Gentlemen:

This refers to the inspection conducted on July 2 through July 29, 1995, at the St. Lucie facility. The purpose of the inspection was to determine whether activities authorized by the license were conducted safely and in accordance with NRC requirements. At the conclusion of the inspection, the findings were discussed with those members of your staff identified in the enclosed report.

Areas examined during the inspection are identified in the report. Within these areas, the inspection consisted of selective examinations of procedures and representative records, interviews with personnel, and observation of activities in progress.

Within the scope of the inspection, violations or deviations were not identified.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be placed in the NRC Public Document Room.

Should you have any questions concerning this letter, please contact us.

Sincerely,

Kerry D. Landis

Kerry D. Landis, Acting Chief
Reactor Projects Branch 3
Division of Reactor Projects

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

Enclosure: NRC Inspection Report

cc w/encl: See page 2

ATTACHMENT 2

9509070211 3PP

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UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA STREET, N.W., SUITE 2900
ATLANTA, GEORGIA 30323-0199

Report Nos.: 50-335/95-14 and 50-389/95-14

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: July 2 through July 29, 1995

Lead Inspector: R. Prevatte, Senior Resident Inspector — 8/8/95 Date Signed

M. Miller, Resident Inspector

Approved by: K. Landis — 8/22/95 Date Signed
K. Landis, Chief
Reactor Projects Section 2B
Division of Reactor Projects

SUMMARY

Scope: This routine resident inspection was conducted onsite in the areas of plant operations review, maintenance observations, surveillance observations, engineering support, plant support, review of nonroutine events, followup of previous inspection findings, and other areas.

Inspections were performed during normal and backshift hours and on weekends and holidays.

Results:

Plant operations area:

Operations continued to perform well. Operator response to a reactor trip on July 8 was excellent. Operations response to deficiencies identified during plant systems walkdowns was satisfactory.

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Maintenance and Surveillance area:

Maintenance performance was found to be good. Critical maintenance on the 1B Auxiliary Feedwater Pump was performed very well; in contrast, a lack of proper planning and preparation resulted in increased out of service time for preventive maintenance on the 2C Auxiliary Feedwater Pump. A personnel error during main turbine trip surveillance testing resulted in a trip on Unit 1. An I&C procedural weakness was identified during testing of the 2B Diesel Fuel Oil Day Tanks.

Engineering area:

Performance in this area continued to be satisfactory.

Plant Support area:

Performance in this area continued to be satisfactory.

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

REPORT DETAILS

1. Persons Contacted

Licensee Employees

R. Ball, Mechanical Maintenance Supervisor
*E. Benkin, Plant Licensing Engineer
*W. Bladow, Site Quality Manager
L. Bossinger, Electrical Maintenance Supervisor
H. Buchanan, Health Physics Supervisor
*C. Burton, St. Lucie Plant General Manager
R. Dawson, Licensing Manager
D. Denver, Site Engineering Manager
J. Dyer, Maintenance Quality Control Supervisor
H. Fagley, Construction Services Manager
P. Fincher, Training Manager
*R. Frechette, Chemistry Supervisor
K. Heffelfinger, Protection Services Supervisor
*J. Marchese, Maintenance Manager
W. Parks, Reactor Engineering Supervisor
*C. Pell, Outage Manager
*L. Rogers, Instrument and Control Maintenance Supervisor
D. Sager, St. Lucie Plant Vice President
*J. Scarola, Operations Manager
J. West, Site Services Manager
C. Wood, Operations Supervisor
W. White, Security Supervisor

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

NRC Personnel

* M. Miller, Resident Inspector
* R. Prevatte, Senior Resident Inspector
* S. Sandin, Senior Operations Officer, AEOD

* Attended exit interview

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

2. Plant Status and Activities

a. Unit 1

Unit 1 entered the inspection period at full power. A reactor trip was experienced on July 8 due to personnel error during a surveillance test. The unit achieved criticality on July 11 and was placed back on-line on July 12. The unit remained at full power for the balance of the period.

b. Unit 2

Unit 2 operated at essentially full power throughout the period until a planned power reduction on July 23 for condenser waterbox cleaning. The unit was maintained at approximately 60 to 70 per cent power during the cleaning, and was returned to full power operation on July 28.

c. NRC Activity

K. D. Landis, Acting Chief, Reactor Projects Branch 2, NRC Region II, visited the site on July 14. His activities included meetings with licensee management and a review of resident inspection activities.

R. P. Carrion of the Division of Radiological Safety and Safeguards, NRC Region II, conducted an inspection of the licensee's chemistry program with the NRC Region II Mobile Laboratory on July 17 and 18. His activities are documented in Inspection Report 95-13.

3. Plant Operations

a. Plant Tours (71707)

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.

The inspectors routinely conducted main flow path 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:

1) Unit 1 Boric Acid Makeup

The inspector found major flowpath valves properly aligned.

2) Unit 1 Auxiliary Feedwater

The inspector found major flowpath valves properly aligned. Corrosion was found breaking through exterior paint on welded joints on either side of V09303 and on the downstream side of V9104. These conditions were brought to the attention of the system engineer for resolution.

Additionally, the inspector examined the governor valve stems of turbine-driven auxiliary feedwater pumps 1C and 2C for evidence of corrosion that could inhibit free movement as identified in NRC Information Notice 94-66, Supplement 1. No significant evidence of corrosion was identified on either stem. The inspector discussed the issue of stem corrosion with the AFW system engineer and found that the issue was being considered and tracked under STAR 950496 and that the system engineer was extremely knowledgeable of the issue.

3) Unit 2 Auxiliary Feedwater

The inspector performed a walkdown of the Unit 2 AFW System in the CST area, AFW Pump Rooms, Steam Trestle area, and the Unit 2 Control Room. All valves in the above areas were in the proper position for current plant conditions. General and specific comments are itemized below.

a) General Comments:

(1) Nameplate identification inconsistent with description in operating procedure.

b) Operating Procedure No. 2-0700022, Rev 35, "Auxiliary Feedwater - Normal Operation:"

(1) SE-08-1 and V08660 were listed as located in the 2C AFW Pump Room on the alignment of Steam Supply System when, in fact, they were in the 2A/2B AFW Pump Room.

(2) V09149, V09150, V09542, V09543, V09313, V09314, V09540, V09541, V09133, V09134, V09544, V09545, V09155, V09156, V09546, V09547 were LOCKED CLOSED valves. Initial lineup per the OP was CLOSED only.

(3) V09540 and V09541 were LOCKED CLOSED with no valve label or position tag attached. They appeared to be replacement valves.

These conditions were referred to the licensee for correction.

4) Unit 2 Component Cooling Water

The inspector verified the major CCW flow paths, reviewed applicable procedures and walked down the system in the CCW Surge Tank area, Unit 2 Control Room HVAC area and the CCW structure. All valves in the above areas were in the proper position for current plant conditions. General and specific comments are itemized below.

a) General Comments:

(1) Nameplate identification inconsistent with descriptions in the system operating procedure.

(2) Description of valves differ between Administrative Procedure No. 2-0010123, Rev 67, "Administrative Control of Valves, Locks and Switches," Appendix I and Operating Procedure No. 2-0310020, Rev 32, "Component Cooling Water - Normal Operation."

(3) Tag missing on SH21339 (8" Drain SS-21-1B) ICW System

b) Operating Procedure No. 2-0310020, Rev 32, "Component Cooling Water - Normal Operation:"

(1) V14101 & V15536 were initially aligned to the CLOSED position; however, both had a handwheel locking device installed with no associated tag indicating LOCKED CLOSED.

(2) Line 4"-FP-126 upstream of V15536 (Fire Protection System to CCW surge tank) painted blue instead of red as on Unit 1.

(3) V14559 (LS-14-6B lower isol) omitted from initial lineup.

(4) V14438 (2A CCW HX outlet piping high point vent) omitted from initial lineup.

(5) SB14439 was initially aligned to the closed position; however, a handwheel locking device was installed with an associated tag indicating LOCKED CLOSED. This valve was also shown in Administrative Procedure No. 2-0010123, Rev 67, "Administrative Control of Valves, Locks and Switches," Appendix I as LOCKED CLOSED.

(6) V14187 (Chemical Feed Tank outlet) tag not attached.

(7) V14188 did not have a LOCKED CLOSED tag as shown in the initial alignment.

c) Off-Normal Operating Procedure No. 2-0030131. Rev 49, "Plant Annunciator Summary:"

(1) Identified sensing element for alarm S-12 as PT-14-8B, vice PIS-14-8B as indicated on CWD.

(2) Identified sensing element for alarm S-42 as TIS-14-29-2B1/2B2, vice TIS-14-29-1B1/1B2 as indicated on CWD.

(3) Identified control room indication as "Check FIS-14-10A on RTGB-206" vice FIS-14-10B for alarm S-25.

d) FSAR Table 9.2-7, "Component Cooling Water System Instrumentation Application:"

(1) Identified CCW Hx Shell Side Outlet Radiation Recorders as RR-2G-1,-2, vice RR-26-1,-2 as shown on CWD.

(2) Identified Fuel Pool HX Outlet Temperature Tag Number as TE-14-2, vice TE-14-20 as shown on CWD.

(3) Identified RCP & Motor Cooling Water Outlet total Combined Flow tag number as FIS-14-15F, vice FIS-14-15B and the instrument range as 0-1500 gpm vice 0-2000 gpm.

(4) Identified RCP & Motor Cooling Water Outlet Seal Cooler HX Tag Number as TDIS-, vice TIS.

These conditions were referred to the licensee for correction.

b. Plant Operations Review (71707)

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 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.

1) Vehicle Accident in Plant Discharge Canal

On July 9, an automobile was inadvertently driven into the plant discharge canal. The automobile was occupied by three teenagers, who later reported that they were looking for a place to surf. The occupants escaped by crawling out of the windows just prior to the vehicle being sucked into the 12' discharge pipe which routes water from the discharge canal, under the beach, into the Atlantic Ocean.

The automobile subsequently became lodged in the discharge pipe at a "Y" which split the 12' pipe into two discharge paths. The obstruction created by the vehicle did not adversely affect safety at the facility, as a 16' pipe also existed parallel to the 12' pipe. The combined discharge capacity was more than sufficient to pass the effluent from both units' ICW pumps without raising discharge canal levels to a level which would have resulted in a spillover of water into the adjoining mangroves.

The vehicle was removed by a combination of divers, who repositioned the vehicle, and a tug boat, which pulled the vehicle from the pipe. The vehicle was subsequently raised and removed from the area.

2) Unit 1 Restart

The inspector observed activities associated with the approach to criticality of Unit 1 on July 11. The evolution was supported by a reactivity manager, Reactor Engineering, and plant management. The inspector verified that ECCs were prepared correctly and were within periods of applicability, that a 1/M plot was being prepared and maintained, and that control room staffing was adequate and controlled. Overall, the evolution was performed in a professional manner. The unit was placed on-line at 12:35 a.m. on July 12.

3) CEDM Cooling Fan Failure

On July 22, Unit 1 control room operators noted that HVE-21B, the B CEDM cooling fan, had tripped off and that HVE-21A, the standby fan, had started. Subsequent testing indicated that the motor for HVE-21B would start and run; however, amperage readings indicated the fan to be running at no-load conditions. A containment entry and inspection revealed that the fan had failed catastrophically, resulting in a low air flow trip.

The fan in question was one of two designed to draw air from the reactor cavity around the CEDMs, pass the air through coolers, and discharge it to the containment environment. One fan was required at all times for power operation, and a loss of both fans required the unit to be subcritical within 45

minutes per ONOP 2-2000030, Rev 9, "Loss of Reactor Cavity, Reactor Support, CEDM, or Containment Cooling Fans."

The failure resulted in the cocking of the fan at an angle from horizontal, cocking of the motor shaft/fan shaft at the coupling, damage to the variable vane linkage and supports, damage of pitot tubes in the discharge plenum, and damage to pillow block bearings supporting the motor/pump union. At the point of failure, parts were dislodged and thrown from the unit, creating holes in the fan shroud and in the screen which covered the fan discharge. The licensee found debris scattered about the area surrounding the fan. The debris which was ejected did not damage adjacent equipment.

At the close of the inspection period, the licensee was attempting to determine root causes and corrective actions. Corrective action options included repair at reduced power, repair during a shutdown, and repair during the upcoming Unit 2 refueling outage.

c. Plant Housekeeping (71707)

Storage of material and components, and cleanliness conditions of various areas throughout the facility were observed to determine whether safety and/or fire hazards existed. No violations or deviations were identified.

d. Clearances (71707)

The inspector reviewed clearances 2-95-04-052, 2-95-06-106, and 2-95-06-095. All tags were in place and components were found to be correctly positioned.

e. Technical Specification Compliance (71707)

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.

1) Elevated Sea Water Temperature

On July 7, the licensee noted that increased sea water temperatures were approaching the operating limits for the Unit 2 ICW/CCW heat exchangers. Sea water temperature had reached

approximately 87°F. Control room operating curves for the heat exchangers, which plotted maximum allowable intake temperature against existing heat exchanger differential pressure, were clamped such that intake temperatures in excess of 88°F would result in heat exchanger inoperability. Dual heat exchanger inoperability would have necessitated entry into TS 3.0.3, requiring a unit shutdown.

The licensee's immediate actions were to check the calibration of the installed temperature indicators on the B heat exchanger (the higher reading of the two) and to install a more accurate, digital, temperature indicator in its place. The inspector observed portions of the calibration and data gathering effort and noted good involvement by the NPS, who sought to ensure that limits were not being violated. The M&TE employed for the measurements was verified to be within its calibration interval. The inspector spoke to control room operators about the issue and found that they had been issued clear instructions to commence a unit shutdown should temperature exceed 88°F.

The more accurate temperature instruments indicated that intake temperature plateaued at approximately 87°F. Concurrently, Engineering began to develop new operating curves which incorporated actual heat exchanger performance data (e.g. number of tubes plugged, actual pump degradation values) to arrive at new temperature/flow relationships. As a result, Engineering determined that the maximum allowable temperatures for each heat exchanger exceeded 89°F at conditions of greatest flow. The inspector discussed the methodologies employed in deriving the curves with Engineering personnel and found them to be acceptable.

f. Effectiveness of Licensee Controls in Identifying, Resolving, and Preventing Problems

1) QA Audit Review (40500)

a) The inspector reviewed Q.A. Audit QSL-OPS-95-14 "Corrective Action" dated June 29, 1995. This audit evaluated the implementation and effectiveness of the plant's corrective action program. The report found that the program was effectively implemented but identified three areas that needed improvement. These included:

- The database did not provide accurate information regarding the responsibility for and current status of pending corrective actions. Changes that occur in status were not always communicated to the STAR Coordinator.

- Several instances were identified where STARs requiring work or repair on ASME Section XI components were not routed to the ANII or ISI Coordinator.

- The authentication process for STARs that become quality records was not clearly delineated. This resulted in some STARs in the quality records system not meeting procedural and quality records requirements.

The audit appeared to be detailed and provided management with a clear understanding of the current STAR system status.

b) The inspector reviewed QA Audit QSL-OPS-95-13, which summarized performance monitoring activities in the areas of ILRT/LLRT programs, CMM, corrections of discrepant field conditions, Maintenance Department corrective actions, M&TE programs, and protected area controls. In general, the audit found the subject activities to be performed satisfactorily. The inspector noted that a number of minor changes in M&TE control and storage methods resulted from one of the PMONs and that the nature of the changes appeared to offer opportunities for greater control of M&TE. The inspector concluded that the audit was both detailed and multidisciplinary.

2) Post-Trip Review (92901)

The inspector attended a meeting, conducted on July 21 by Operations management, which discussed the Unit 1 High Pressure trip discussed in paragraph 4.b, below. This was the second such meeting following an automatic trip, and was designed to elicit comments from plant operations and support personnel on ways to avoid similar trips in the future. Presentations covered the circumstances surrounding the event, the effect on the unit, preliminary lessons learned and an open discussion of options to prevent recurrence. The meeting was heavily attended and input and exchanges were frank. The inspector concluded that this practice continues to provide plant management with practical options for reducing the number of automatic trips in the future.

g. Followup of Operations LERs (90712)

(Closed) LER 50-389/94-006, Rev 1, "Trip Circuit Breaker Failure due to a Broken Piece of Phenolic Block Lodged in the Trip Latch Mechanism"

The licensee provided the subject LER as informational following the failure of a TCB to open during RPS logic matrix testing in July, 1994. The incident which prompted the LER is described in IR 94-15. The licensee's corrective actions involved a replacement of the subject TCB, an inspection of the remaining Unit 2 TCBs and CEA MG output breakers, an inspection of Unit 1 TCBs (discussed in IR 94-24), and an evaluation of the use of a locking compound on cutoff switch phenolic block screws to prevent the backing out of the screws (believed to be responsible for the subject failure).

The licensee's corrective actions have been completed. No similar conditions were noted in TCB inspections and no loose screws were found. The licensee and the vendor concluded that the application of locking compounds was not necessary. The licensee determined that routine, periodic, inspections would suffice to detect loosening of the subject screw. The inspector concluded that the licensee's actions were appropriate to the circumstances.

Revision 1 to this LER also documented a failure to perform a TS required shutdown as a result of an inoperable TCB channel. This aspect of the event was documented as VIO 94-15-01. The licensee's corrective actions were found to be satisfactory and the violation was closed in IR 94-24. This item is closed.

h. Self Contained Breathing Apparatus (SCBA) Needs and Availability Survey (71707, 64704)

The following information was provided by the licensee in response to a questionnaire prepared by NRC Region II:

1) Facility Name.

St. Lucie Nuclear Power Plant

2) Event(s) which require operators in the control room to wear SCBA to safely operate/shutdown the plant.

FSAR states chlorine but chlorine is no longer stored or used onsite.

3) For the limiting event, does the licensee have SCBAs available for each staff member filling a required position for operation or safe shutdown?

5 SCBAs stored in each Control Room.

4) Are all staff members filling required positions for operations or safe shutdown SCBA qualified?

No, but licensee has plans that will qualify required Operations personnel by July 31, 1995.

5) Are SCBAs readily available at required use location.

Yes

6) Have provisions been provided for special needs associated with SCBA use, i.e., eye glasses with face mask inserts.

No, on eye wear. Licensee will correct by July 31, 1995.

7) What is the minimum number of spare air bottles for each user.

None provided in Control Room. Stored in fire house and RCA.

8) Has the licensee established plans to protect personnel not assigned a SCBA?

Yes. If emergency responder will be SCBA qualified.

9) Does the licensee have SCBAs available for NRC use?

None specifically assigned to NRC, but available for issue at HP.

10) Initials of each resident and indicate if he/she is SCBA qualified.

RLP - Yes, MSM - Yes

11) If not qualified, discuss steps necessary to have residents SCBA qualified with your Branch Chief.

N/A

12) Comment field.

Chlorine not onsite - FSAR will be corrected next update.

4. Maintenance and Surveillance

a. Maintenance Observations (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:

1) 2C Auxiliary Feedwater Pump Preventive Maintenance

The inspector observed an oil change on the 2C AFP, conducted per PWO 62/4389. Work was performed in accordance with 2-M-0018, Rev 42, "Mechanical Maintenance Safety-Related Preventive Maintenance Program." The inspector verified that proper replacement oil was used, that the old oil was free of visible contaminants, that the final oil level was adequate, and that the new oil filter was a direct replacement for the old one. The inspector also observed the lubrication of the turbine's trip throttle linkage, performed under PWO 62/4421, and verified that the proper grease and graphite spray was used.

The inspector found that the quality of the work performed was satisfactory; however, the timeliness of the work was found to suffer from inadequate prior planning. The work had been scheduled to begin at midnight on July 18. In support of the evolution, Operations declared the subject AFP OOS at 9:20 p.m. on July 17. At 1:00 a.m., an electrician arrived at the work site to disconnect a lube oil immersion heater which required removal for the oil change to take place. This task was completed in approximately five minutes. At approximately 3:10 a.m., mechanics arrived to perform the oil change. As a result, the subject pump was out of service for approximately six hours before the subject task was begun in earnest.

The inspector discussed the timeliness of the maintenance with Maintenance Supervision, who stated that the personnel involved in the oil change had questioned a procedure revision which changed the specification of the lubricating oil from that used the last time they had performed the task. Additional complications were experienced in employing the licensee's new PASSPORT system to obtain spare bottles and jugs to support the work. It was acknowledged in these discussions that the job was not properly pre-planned/pre-staged, and that the confusion could have been dealt with prior to the initiation of work.

Given the licensee's development of a critical (on-line) maintenance process, the inspector reviewed AP 0010460, Rev 3, "Critical Maintenance Management." In general, the procedure required that work on TS equipment, involving a voluntary entrance into a TS AS, be preplanned and expedited. However, the inspector noted that section 3.1.3 of the subject procedure stated that the procedure need not apply to "Routine preventive maintenance on equipment required more frequently than 18 months that is not risk significant..." The subject maintenance activity constituted a quarterly PM and therefore was outside the requirements of the procedure. The inspector discussed the issue with licensee management, who acknowledged

the apparent dichotomy between the CMM process's mandate that time in a TS AS be minimized for some maintenance evolutions but not for others. The licensee stated that they would consider the issue.

The inspector concluded that no regulation was violated, as the licensee was well within the AOT for the 2C AFP and the maintenance in question was performed satisfactorily and within the bound of the licensee's programs and procedures. However, the inspector found that preplanning for the evolution was poor and unnecessarily increased the out of service time for the 2C AFP.

2) Auxiliary Feedwater Pump 1B Critical Maintenance

The inspector observed maintenance activities performed on the 1B AFP on July 20. The work was conducted under the guidance of AP 0010460. Rev 3, "Critical Maintenance Management." Specific observed activities included:

- PWO 61/4933 - Replacement of pump bearing Trico oilers with indicating sight glasses and installation of oil sample test fittings. The replacement was conducted per 1 MMP-09.01. "Auxiliary Feedwater Pumps 1A and 1B Disassembly, Inspection. and Reassembly Mechanical Maintenance." and Procurement Engineering evaluation 036912. The inspector verified that the installation was conducted satisfactorily and in accordance the governing documents.

- PWO 61/4974 - 1B AFP coupling and thrust bearing checks. The subject activity was conducted under 1-MMP-09.01, "Auxiliary Feedwater Pumps 1A and 1B Disassembly, Inspection, and Reassembly Mechanical Maintenance." The inspector observed coupling disassembly and cleanup, pump thrust bearing endplay measurement, coupling reassembly and final torquing. The inspector noted that pump endplay was acceptable (.006") and that the mechanics performing the work properly reassembled and torqued the pump coupling. The torque wrench was verified to be in calibration.

Overall, the inspector found that the maintenance evolution was performed very well. Jobs were worked concurrently, QC coverage was detailed and thorough, parts and tools were adequately prestaged, and the evolution was completed expeditiously. The inspector noted that the time the component was OOS, including the post-maintenance surveillance run, was only approximately eight hours.

3) PWO 64/4966 - Unit 2 Plant Vent WRGM Loss of Counts

The inspector observed portions of the troubleshooting effort in response to a failure of the Unit 2 WRGM. I&C personnel performing the evolution were found to be very knowledgeable of the equipment's construction and operation. Troubleshooting was methodical and thorough. M&TE used in the effort was verified to be within its calibration interval. The source of the failure was determined to be a high voltage power supply to the unit's detector.

b. 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:

1) OP 1-0030150, Rev 74, "Secondary Plant Operating Checks and Tests, Section 8.2 through 8.8 Turbine Trip Test."

The inspector attended the prejob briefing and found that the procedural steps, requirements and precautions were discussed in detail with all personnel involved in the test.

The inspector then observed the overspeed, thrust bearing and low vacuum trip tests. The low bearing oil pressure trip could not be done since valve V22174, low bearing oil pressure trip drain valve could not be operated. PWO #74457 was attached to the valve indicating that work was needed. The other above tests were completed satisfactorily.

The operator then proceeded to test the 20/ET, EH Fluid Trip Header Solenoid valve and the 20-1/OPC and 20-2/OPC Overspeed Protection Solenoid valves. This test consisted of opening the EH test header valves to the solenoid under test; unlocking and closing the EH inlet isolation valve under test; inserting and turning the trip test key.

This test was completed satisfactorily on 20/ET. When the second solenoid valve was tested, the operator opened the EH test header valve, V22493, and unlocked, but <u>did not close</u>, the solenoid inlet isolation valve V22482 as required by the procedure. After unlocking and removing the lock he laid down

the lock, read the procedure, and then inserted the test key into the 20-1/OPC test switch and turned it to the test position. A loud noise was noted as the governor valves went shut, the turbine tripped, and the main steam safety valves opened.

The inspector and the NWE then went to Unit 1 control room. In the control room, the operators responded to the event as required by EOP-01, "Standard Post Trip Actions." All rods inserted and equipment responded to the event as designed. The reactor tripped on High Pressurizer Pressure as a result of the Governor and Reheat valves going shut. Steam Generator "A" experienced a high level, but operator action isolated feed and the level was restored to normal. Overall, operator response to the event was considered excellent.

The NLO performing the surveillance test openly acknowledged that he inadvertently failed to close the EH inlet isolation valve V22482 per procedural step 8.6.5.(B) while performing the solenoid valve tests and that this resulted in tripping the unit. The NWE supervising the test stated that he became too involved in radio communications with the control room and did not verify that each step was completed in sequence.

The inspector also noted that procedural step 8.6.5.B and several other steps contained two required actions in one procedural step and that this may have led to the error. He also noted that the use of hand held radios vice sound powered head sets for communications may have been a contributing factor.

The unit was placed in a stable plant condition using 1-EOP-02, "Reactor Trip Recovery." A decision was then made to accomplish several outstanding maintenance activities prior to plant restart. This work included:

- Relocate Channel "D" NIS jumper from the control room to the Reactor Building Keyway area
- Rework 3 CEA reed switches
- Repair 1A FW Regulating valve
- Inspect/repair RCP vibration probe
- Repair RPS Channel "C" Wide Range NIS (failed low after reactor trip)
- Repair Main Generator excitation power supply
- Repair loose connection on 1B Motor Generator set
- Stroke test MV-08-8
- Repair MV-09-6
- Cleaning Main Condenser Water boxes A1 and B2
- Other minor maintenance activities

The above work activities, except the NIS Channel "C" Wide Range, were completed by the morning of July 9. Completion of

the repair to NIS Channel "C" Wide Range, and concerns relating to high discharge canal levels resulting from unusually high tides and an automobile lodged in a discharge canal pipe (discussed in paragraph 3.b.1), delayed reactor restart until July 11.

The inspector reviewed the above work activities and found them satisfactory. The reactor trip package was also reviewed and it was determined that all issues had been satisfactorily resolved to permit plant restart.

2) OP 1-0700050, Rev 50, "Auxiliary Feedwater Periodic Test"

The inspector observed the surveillance test, conducted per the above procedure, on the 1B AFP following CMM work discussed in paragraph 4.A.2, above. The test involved an ASME Section XI code run of the subject pump. The inspector noted that the operator conducting the test locally had procedure in-hand and that M&TE employed for obtaining vibration and temperature data was within its calibration interval. The required time interval was observed prior to data collection (5 minutes), discharge pressure was greater than the minimum specified for compliance with TS (1342 psig), and results were satisfactory (3241.7 ft developed head).

3) OP 2-2200050B, Rev 20, "2B Emergency Diesel Generator Periodic Test and General Operating Instructions"

The inspector witnessed portions of this test, conducted July 26. The test involved a fast start of the 2B EDG to satisfy TS surveillance requirement 4.8.1.1.2.a.4, which required that the EDG achieve rated speed and voltage within 10 seconds at least once per 184 days.

The inspector witnessed pre-start checks performed by the SNPO and found them to be performed satisfactorily with procedure in-hand. The inspector observed the EDG start and examined the operating machines for signs of previously unidentified leaks. None were noted. The machines started and loaded satisfactorily, with a start time of 9.65 seconds.

4) EDG Day Tank Level Switch Surveillance

The inspector observed portions of surveillance tests, performed in accordance with I&C Procedure 2-1400064L, Rev 32, "Installed Plant Equipment Calibration (Level)," Appendix B, Tab 10, "Diesel Oil Day Tank Lo/Lo level Verification," to verify day tank level switch setpoints on the 2B EDG day tanks. The tests were performed by attaching tygon tubes to drain valves located, hydraulically, at the bottoms of the day tanks and routing the tubes vertically to the tops of the tanks.

Rulers were then located next to the tubes to provide local level indication in the tanks to assess alarm setpoints.

The test methodology for testing hi/hi level alarms was to align the temporary standpipes with their respective day tanks and manually operate the tanks' fill solenoid valves to admit fuel until the hi/hi level alarms were received. The inspector noted that the I&C personnel performing the tests were sensitive to the fact that indicated level increase rates would accelerate as the levels approached the tops of the tanks, as the tanks were horizontally oriented cylinders. Nonetheless, while filling the 2B1 day tank, the level in the tygon tube rose rapidly and resulted in a small spill (approximately two cups) of FO. The spill was quickly terminated, contained to a small area around the day tank, and cleaned up by the I&C personnel performing the test. Additionally, the hi/hi level alarm did not energize. Upon inspection, it was noted that a PWO tag was hung on the level alarm, indicating inoperability of either the circuit or the sensor. The I&C personnel performing the test acknowledged not checking the PWO tag prior to beginning the test. Testing of the lo/lo level alarms resulted in satisfactory results.

The inspector discussed the performance of the test with I&C personnel, who stated that the hi/hi level alarm did not energize due to the fact that the 2B2 day tank hi/hi alarm was energized as a result of performing the same test on it previously. As the hi/hi level alarms had no reflash capability, the second day tank's alarm could not annunciate. I&C personnel conceded that the governing procedure was inadequate to test the hi/hi alarms as written, and stated that the procedure would be revised. Possible new test methodologies included:

- Testing the second tank's alarm after the first tank's alarm had cleared due to engine fuel consumption, or

- Performing the test by monitoring level switch output state, as opposed to the alarm annunciator

I&C personnel stated that the PWO which was written to document hi/hi level switch inoperability was most probably the result of a similar failure in a similar test. The inspector concluded that the FO spill could have been avoided if either the tygon tubing had been run further in elevation above the day tank or if the workers performing the test had recognized that the level switch they were testing would not result in annunciation due to the alarm condition in the 2B2 day tank. In reviewing the governing procedure, the inspector noted the following weaknesses:

- The title for Tab #10 of the procedure ("Diesel Day Tank Lo/Lo Level Verification") was misleading in that hi/hi level alarm verification was also included. This point was reinforced in the body of the procedure in step B.2 when personnel were directed to place a measurement scale from 20" to 25" up the sight glass, when hi/hi level alarm verification would also require a measurement scale at approximately 34". Personnel performing the observed test showed foresight in extending the measurement scales along the full length of the sight glasses.

- The procedure directed that tygon tubes be taped to the top of the day tanks. The physical arrangement of the day tanks' overflow lines was such that the FO level could increase approximately 1' above the tops of the tanks prior to the overflow being directed away, increasing the potential for spills.

The inspector concluded that the performance of the subject surveillance test suffered from procedural weakness and an inadequate pre-test observation of the component to be tested.

5) Containment Anomalies Inspection - Unit 2

The inspector accompanied Unit 2 NLOs on an inspection of accessible containment areas on July 25. Damage to HVE-21B, described in paragraph 3.b.3, above, was noted. The status of a packing leak from V8453, a root valve for B channel SG level and pressure instruments, was inspected and found to be unchanged. Several instances of boric acid buildup on instrument tubing was also noted. Otherwise, no adverse conditions were identified. The inspector found that the NLOs conducting the inspection proceeded swiftly but were thorough in their inspections, allowing for a comprehensive tour while maintaining dose rates ALARA.

5. Engineering Support (37551)

A. Safety Evaluation JPN-PSL-SENS-95-013

The inspector reviewed the subject SE, prepared to allow operation with a manual isolation valve closed in the 2B EDG FO line from the DOST to the day tanks. The configuration was proposed when the a leak was determined to exist in the underground line between the two tanks. The action was designed to minimize the amount of FO released to the environment until the leak could be identified and corrected.

As a compensatory measure, the licensee proposed dedicating an NLO to the task of opening the closed valve in the event of an EDG start. The licensee calculated that the EDG day tanks contained enough FO to allow 126 minutes of EDG operation at full load before

a transfer of FO was required. The licensee then specified that the NLO would be required to open the valve within 20 minutes of an EDG start. Procedures were revised to include direction to open the valve on an EDG start, and administrative controls were put in place to ensure that the NLO would not be required to perform any other immediate response duties. Additionally, the licensee performed a response time test, placing the operator at the G-2 warehouse (as far away from the EDG as he could credibly be in the PA) and requiring the NLO to proceed to the valve and open it. The NLO performed this task in approximately seven minutes.

In considering the issue, the licensee employed PRA techniques to estimate the increase in the risk of the loss of the 2B3 bus due to a failure of either the operator to open the valve or a failure of the valve to be able to be opened. The licensee concluded that the increase in probability was approximately 6 percent. However, in considering 10 CFR 50.59 criteria, the licensee concluded that no increase in the probability of failure of a component important to safety was created by the proposed action. The inspector questioned the licensee on this issue. The licensee explained that a deterministic conclusion of no increased probability was reached when the existence of procedural guidance and heightened awareness was balanced against the approximate 6 percent increase in failure probability presented by the two new failure modes.

In the context of regulatory compliance, the inspector noted that 10 CFR 50.59 was written in terms of absolute increases in the probabilities of failure represented by a proposed change. The inspector continued to question whether 10 CFR 50.59 criteria could ever be satisfied when new failure modes are imposed on a previously reviewed system (i.e whether added risk, once qualitatively established, could be completely mitigated). The inspector concluded that insufficient guidance existed from a regulatory perspective to take immediate issue with the licensee's rationale. Further, the inspector concluded that the licensee had taken prudent measures to ensure the continued operability of the 2B EDG while minimizing the FO leak's effect on the environment. The inspector referred the question to NRR for resolution.

6. Plant Support (71750)

a. Fire Protection

During the course of their normal tours, the inspectors routinely examined facets of the Fire Protection Program. The inspectors reviewed transient fire loads, flammable materials storage, housekeeping, control hazardous chemicals, ignition source/fire risk reduction efforts, fire protection training, fire protection system surveillance program, fire barriers, fire brigade qualifications, and QA reviews of the program. No deficiencies were identified.

b. Physical Protection

During this inspection, the inspector toured the protected area and noted that the perimeter fence was intact and not compromised by erosion or disrepair. The fence fabric was secured and barbed wire was angled as required by the licensee's Physical Security Plan (PSP). Isolation zones were maintained on both sides of the barrier and were free of objects which could shield or conceal an individual.

The inspector observed personnel and packages entering the protected area were searched either by special purpose detectors or by a physical patdown for firearms, explosives and contraband. The processing and escorting of visitors was observed. Vehicles were searched, escorted, and secured as described in the PSP. Lighting of the perimeter and of the protected area met the 0.2 foot-candle criteria.

In conclusion, selected functions and equipment of the security program were inspected and found to comply with the PSP requirements.

c. Radiological Protection Program

Radiation protection control activities were observed to verify that these activities were in conformance with the facility policies and procedures, and in compliance with regulatory requirements. These observations included:

- Entry to and exit from contaminated areas, including step-off pad conditions and disposal of contaminated clothing;
- Area postings and controls;
- Work activity within radiation, high radiation, and contaminated areas;
- Radiation Control Area (RCA) exiting practices; and,
- Proper wearing of personnel monitoring equipment, protective clothing, and respiratory equipment.

No violations or deviations were identified.

7. Exit Interview

The inspection scope and findings were summarized on July 27, 1995, with those persons indicated in paragraph 1 above. The inspector described the areas inspected and discussed in detail the inspection results listed below. Proprietary material is not contained in this report. Dissenting comments were not received from the licensee.

Type	Item Number	Status	Description
LER	50-389/94-006, Rev 1	Closed	"Trip Circuit Breaker Failure due to a Broken Piece of Phenolic Block Lodged in the Trip Latch Mechanism", paragraph 3.g.2).

8. Abbreviations, Acronyms, and Initialisms

AEOD	Analysis and Evaluation of Operational Data, Office for (NRC)
AFP	Auxiliary Feedwater Pump
AFW	Auxiliary Feedwater (system)
ALARA	As Low as Reasonably Achievable (radiation exposure)
ANII	Authorized Nuclear Inservice Inspector
ASME Code	American Society of Mecnanical Engineers Boiler and Pressure Vessel Code
CCW	Component Cooling Water
CEA	Control Element Assembly
CEDM	Control Element Drive Mechanism
CIS	Containment Isolation System
CMM	Critical Maintenance Management
CWD	Control Wiring Diagram
DG	Diesel Generator
ECC	Estimated Critical Concentration
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EOP	Emergency Operating Procedure
ESF	Engineered Safety Feature
ESFAS	Engineered Safety Feature Actuation System
FO	Fuel Oil
FSAR	Final Safety Analysis Report
FW	Feedwater
gpm	Gallon(s) Per Minute (flow rate)
HVAC	Heating Ventilation and Air Conditioning
HVE	Heating and Ventilating Exhaust (fan, system, etc.)
HX	Heat Exchanger
ICW	Intake Cooling Water
ILRT	Integrated Leak Rate Test(ing)
IR	[NRC] Inspection Report
ISI	InService Inspection (program)
JPN	(Juno Beach) Nuclear Engineering
LCO	TS Limiting Condition for Operation
LER	Licensee Event Report
LLRT	Local Leak Rate Test
MMP	Mechanical Maintenance Procedure
MV	Motorized Valve
NIS	Nuclear Instrumentation System
NLO	Non-Licensed Operator
NPS	Nuclear Plant Supervisor
NRR	NRC Office of Nuclear Reactor Regulation

NWE	Nuclear Watch Engineer
ONOP	Off Normal Operating Procedure
OOS	Out Of Service
OP	Operating Procedure
OPS	Operations
PMON	Performance Monitoring
PORV	Power Operated Relief Valve
PRA	Probabilistic Risk Assessment
psig	Pounds per square inch (gage)
PSL	Plant St. Lucie
PWO	Plant Work Order
QA	Quality Assurance
QC	Quality Control
QSL	Quality Surveillance Letter
RCP	Reactor Coolant Pump
RPS	Reactor Protection System
RTGB	Reactor Turbine Generator Board
RWT	Refueling Water Tank
SCBA	Self Contained Breathing Apparatus
SG	Steam Generator
SNPO	Senior Nuclear Plant [unlicensed] Operator
TCB	Trip Circuit Breaker
TS	Technical Specification(s)
WRGM	Wide Range Gas Monitor