Florida Power & Light Company, 6501 South Ocean Drive, Jensen Beach, FL 34957

FPL

May 30, 2003

L-2003-130
10 CFR 54

U.S. Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, D.C. 20555

Re: St. Lucie Units 1 and 2
Docket Nos. 50-335 and 50-389
Supplemental Responses to Safety Evaluation Report Open Items for Review of the St. Lucie Units 1 and 2 License Renewal Application

By letter dated March 28, 2003 (L-2003-070), Florida Power and Light Company (FPL) provided responses to NRC Open Items and Confirmatory Items identified in the NRC's "Safety Evaluation Report with Open Items Related to the License Renewal of St. Lucie Units 1 and 2," dated February 2003. Based on a review of FPL's responses, the NRC has requested additional information regarding FPL's response to Open Item 3.0.5.10-1, related to the intake cooling water supply to the spent fuel pool and Open Item 3.1.2.2-1 related to pressurizer nozzle thermal sleeves. Accordingly, Attachment 1 to this letter contains the supplemental information to support FPL's responses to these open items.

Should you have any further questions, please contact S. T. Hale at (772) 467-7430.

Very truly yours,

William Jefferson, Jr.
Vice President
St. Lucie Plant

WJ/STH/hlo
Attachment

A089

STATE OF FLORIDA )
) ss
COUNTY OF ST. LUCIE )

William Jefferson, Jr. being first duly sworn, deposes and says:

That he is Vice President – St. Lucie of Florida Power and Light Company, the Licensee herein;

That he has executed the foregoing document; that the statements made in this document are true and correct to the best of his knowledge, information and belief, and that he is authorized to execute the document on behalf of said Licensee.

William Jefferson, Jr.

STATE OF FLORIDA

COUNTY OF St. Lucie

Subscribed and sworn to before me this

30 day of May, 2003.

by William Jefferson, Jr. is personally known to me.

Leslie J. Whitwell

Signature of Notary Public – State of Florida

Name of Notary Public (Print, Type, or Stamp)

Leslie J. Whitwell
MY COMMISSION # DD020212 EXPIRES
May 12, 2005
BONDED THRU TROY FAIN INSURANCE, INC.

cc: U.S. Nuclear Regulatory Commission, Washington, D.C.
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Project Manager, St. Lucie License Renewal
Project Manager, St. Lucie

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**ATTACHMENT 1**
**SUPPLEMENTAL RESPONSES TO SAFETY EVALUATION REPORT OPEN ITEM FOR REVIEW OF THE ST. LUCIE UNITS 1 AND 2 LICENSE RENEWAL APPLICATION**

**Open Item 3.0.5.10-1:**

Several components in the intake cooling water system credit the Systems and Structures Monitoring Program for managing loss of material in the raw water environment. In RAI B.2.10-2, the staff asked the applicant to justify the adequacy of this program for managing the aging effects on specific components in the intake cooling water system. The staff finds the applicant's response does not adequately address the aging management of the small valves, piping/tubing/fittings, thermowells, and orifices. The applicant, in a letter dated November 27, 2002, provided additional information concerning the materials, operating history, and repair history of the small valves, piping/tubing/fittings, thermowells, and orifices in the intake cooling water system. However, the applicant also relies on leakage detection for aging management of some components. It is the staff's position that leakage detection does not provide adequate aging management because leakage indicates a loss of component intended function.

**FPL Response:**

This response was provided to the NRC in FPL letter L-2003-070, dated March 28, 2003. Supplemental information to support this response is provided below.

As described in LRA Appendix B, Subsection 3.2, the Systems and Structures Monitoring Program manages the aging effect of loss of material for valves, piping, and fittings at selected locations of ICW by leakage inspection to detect the presence of internal corrosion. These locations mostly encompass small bore piping components, not addressed by the ICW crawl-through inspections due to access limitations. Evaluations have been performed to show that through-wall leakage equivalent to a sheared 3/4 inch instrument line and an additional 100 gpm opening from another location will not reduce the ICW flow to the component cooling water heat exchangers below CLB design requirements. The leakage inspection is adequate in managing the aging effects of loss of material for the following reasons:

a. Maintenance history shows that localized failures of cement lining or internal epoxy coating of intake cooling water lines result in small corrosion cells. These corrosion cells will be detected by small through-wall leakage which provides adequate time for repairs before the system function or structural integrity of the line is degraded.

b. For small valves, piping and fittings, leakage does not affect the system function because the small size of these components limits the leakage. These valves and lines are either constructed of corrosion resistant materials (monel, bronze, aluminum bronze), are concrete or rubber lined, or are epoxy coated carbon steel. The mechanical joints in carbon steel lines are the most susceptible locations due to the interface between the flange face/gasket and the internal lining/coating. Because the joints in carbon steel lines may be exposed to salt water, a specification was developed to provide for the replacement of these lines with monel on an "as required" basis during inspections or when leaks are identified. To date, approximately 75% of the epoxy coated, small carbon steel piping and fittings, and all of the small valves, have been replaced with corrosion resistant materials. Plant operators walk down ICW as part of normal shift activities, and would note any leaks that were present. When leaks are identified, they are immediately documented under the Corrective Action Program and receive prompt engineering evaluation and corrective actions. The operating

and maintenance history of this equipment demonstrates that leakage from this equipment has not been significant.

In addition to the above process, periodic crawl-through inspections of the large bore piping, as described in the Intake Cooling Water Inspection Program, are conducted to identify, evaluate and repair any component degradation. Although no crawl-through inspections can be performed on the small-bore piping, the mechanical joints (i.e., flanged connections) between the small bore and large-bore piping are inspected as part of the crawl-through inspections of the large bore piping. These mechanical joints are representative of other mechanical joints in the small-bore lines and are the most likely locations for corrosion as discussed above. Therefore, the Intake Cooling Water Inspection Program, in conjunction with the Systems and Structures Monitoring Program, provides an effective means of aging management for the internal surfaces of intake cooling water.

Table 3.3-9 of the LRA (pages 3.3-59, 3.3-60, and 3.3-61) is revised as shown below:

**TABLE 3.3-9**
**INTAKE COOLING WATER**

| Component/ Commodity Group [GALL Reference] | Intended Function | Material | Environment | Aging Effects Requiring Management | Program/Activity |
|---|---|---|---|---|---|
| **Internal Environment** | | | | | |
| Valves (strainer bypass, strainer backwash, and spent fuel pool makeup) | Pressure boundary | Carbon steel<br>Cast iron (Unit 1 only) | Raw water – salt water | Loss of material | Systems and Structures Monitoring Program<br>Intake Cooling Water Inspection Program[1] |
| Piping/fittings (strainer bypass and strainer backwash)<br>[VII C1. 1.1] | Pressure boundary | Stainless steel | Raw water – salt water | Loss of material | Systems and Structures Monitoring Program<br>Intake Cooling Water Inspection Program[1] |
| Piping/fittings (strainer bypass, strainer backwash, and spent fuel pool makeup) | Pressure boundary | Stainless steel | Air/gas | None | None required |
| | | Carbon steel | Raw water – salt water | Loss of material | Systems and Structures Monitoring Program<br>Intake Cooling Water Inspection Program[1] |
| | | | Air/gas[2] | None[2] | None required |
| Valves (vents, drains, and instrumentation)<br>[VII C1. 2.1] | Pressure boundary | Stainless steel<br>Aluminum bronze<br>Bronze | Raw water – salt water | Loss of material | Systems and Structures Monitoring Program<br>Intake Cooling Water Inspection Program[1] |
| Valves (vents, drains, and instrumentation) | Pressure boundary | Carbon steel<br>Monel | Raw water – salt water | Loss of material | Systems and Structures Monitoring Program<br>Intake Cooling Water Inspection Program[1] |
| Piping/fittings (vents, drains, and instrumentation)<br>[VII C1. 1.1] | Pressure boundary | Stainless steel<br>Aluminum bronze | Raw water – salt water | Loss of material | Systems and Structures Monitoring Program<br>Intake Cooling Water Inspection Program[1] |

**TABLE 3.3-9 (continued)**
**INTAKE COOLING WATER**

| Component/ Commodity Group [GALL Reference] | Intended Function | Material | Environment | Aging Effects Requiring Management | Program/Activity |
|---|---|---|---|---|---|
| **Internal Environment** | | | | | |
| Piping/fittings (vents, drains, and instrumentation) | Pressure boundary | Carbon steel<br>Aluminum brass<br>Monel | Raw water – salt water | Loss of material | Systems and Structures Monitoring Program<br>Intake Cooling Water Inspection Program[1] |
| | | Fiberglass (Unit 2 only) | Raw water – salt water | Cracking | Systems and Structures Monitoring Program<br>Intake Cooling Water Inspection Program[1] |
| Tubing/fittings | Pressure boundary | Stainless steel | Raw water – salt water | Loss of material | Systems and Structures Monitoring Program<br>Intake Cooling Water Inspection Program[1] |

Notes:

1. Inspection of connections between the large bore and small bore piping.
2. Internal air/gas environment is outside air and is applicable to the spent fuel pool makeup lines. Based upon available corrosion allowance and conservative rates, loss of material due to general corrosion is not an aging effect requiring management.

As described in LRA Appendix B Subsection 3.2.14, "Systems and Structures Monitoring Program," leakage inspections are credited for managing external cracking of selected CVCS valves, piping, and fittings. These leakage inspections only apply to the previously heat traced portions of CVCS (i.e., boric acid make-up lines). A review of St. Lucie plant-specific operating experience for CVCS identified that external stress corrosion cracking (SCC) has occurred in the previously insulated heat traced lines. The SCC was attributed to contaminated insulation due to the water used to wash down external surfaces of piping components. The combination of high halogens (e.g., chlorides) and high temperature (i.e., approximately 180°F) due to heat tracing increased the susceptibility of the lines to SCC. Corrective actions to address this condition included inspection of all susceptible boric acid makeup piping (including liquid penetrant examinations of high chloride concentration areas), replacement of defective portions, and administrative enhancements for cleaning external surfaces of stainless steel piping. Additionally, as part of a boric acid concentration reduction project, CVCS piping insulation has been removed since heat tracing is no longer required. The results of SCC are localized minor leakage (not catastrophic failure of the piping) detectable by periodic visual inspection under the Systems and Structures Monitoring Program. Since the initial identification of SCC and corrective actions taken in 1990, there have only been two occurrences of minor leakage due to external SCC in the previously heat traced lines. One leak occurred in Unit 1 in 1996, and one on Unit 2 in 1998.

Therefore, the Systems and Structures Monitoring Program provides an effective means for aging management of external cracking due to SCC of selected CVCS valves, piping, and fittings.

<u>Conclusion</u>

Based on the above, FPL requests that Open Item 3.0.5.10-1 be closed.

**FPL Response Supplemental information:**

In response to a conference call with the NRC on May 7, 2003, the following additional technical information is provided supporting the basis for note (2) of Table 3.3.9.

The Units 1 and 2 intake cooling water (ICW) emergency makeup lines to the spent fuel pool are designed to ANSI B31.7 and ASME Section III CL 3 requirements, respectively. These lines are constructed of 2 ½ inch schedule 40 carbon steel pipe/fittings. The Unit 2 piping and fittings are concrete lined. The internal surfaces of these lines are exposed to stagnant atmospheric air. The potential aging effect for the Unit 1 piping/fitting internal surfaces is loss of material due to general corrosion. However, for Unit 2, the high alkalinity of the concrete lining in an air environment protects internal steel surfaces from corrosion. Therefore, there are no aging effects requiring management for the Unit 2 emergency makeup line piping/fittings internal surfaces.

The nominal wall thickness of the Unit 1 piping is 0.203 inches and the minimum wall thickness requirement based upon design loading including pressure, thermal seismic, and deadweight is 0.035 inches. Utilizing conservative corrosion rates for "Steel Category A" from Tables 6-1 and F-1 of MCIC Report, July, 1986, "Corrosion of Metals in Marine Environment" by J. A. Beavers, G. H. Koch and W. E. Berry, the worst case loss of material in 60 years is calculated to be 76 mils. As mentioned above, the aging mechanism of concern is general corrosion. Therefore, uniform loss of material is expected and the table column providing average reduction thickness is applicable. Additionally, since the lines are normally isolated, there is little air exchange with the surrounding environment, and thus, the "inland" tropical environment data is applicable. The corrosion rates utilizing this data are 2.8 mils for the first year, 2.3 mils for the second year (i.e., 5.1 cumulative), 3.2 mils for the third and fourth years (i.e. 8.3 cumulative), and approximately 1.1 for each of the next 4 years (i.e., 12.6 mils total for 8 years). For conservatism, a corrosion rate of 3 mils/year was assumed for the first 8 years, followed by a 1 mil/year corrosion rate for the remainder of plant life (3 mils/year x 8 years + 1 mil/year x 52 years = 76 mils).

These corrosion rates are based upon comprehensive evaluations of corrosion damage to steel exposed to tropical atmosphere in the Panama Canal Zone. As expected, the corrosion rates will decrease with time due to the buildup of an oxidation layer which will tend to provide some protection of the bare metal underneath.

Based on the calculated loss of pipe wall thickness of 76 mils in 60 years, the projected pipe wall thickness at the end of the extended operating period is 127 mils (203 mils - 76 mils = 127 mils). This wall thickness greatly exceeds the design minimum wall thickness requirement of 35 mils (0.035 inches).

Therefore, loss of material due to corrosion is not an aging effect requiring management for the internal carbon steel surfaces of the ICW emergency makeup lines (piping/fittings) to the spent fuel pools.

**Open Item 3.1.2.2-1:**

The pressurizer surge and spray nozzle thermal sleeves are fabricated from Alloy 600 materials and are welded to the low-alloy steel pressurizer surge and spray nozzles using Alloy 182/82 weld metals. Industry experience has demonstrated that these weld materials are susceptible to PWSCC. In its AMR provided October 3, 2002, the applicant concluded that there are no applicable aging effects for the pressurizer surge and spray nozzle thermal sleeves because the applied loads on the thermal sleeves are low. The attachment welds for the pressurizer surge and spray nozzle thermal sleeves may contain high residual stresses that result from solidification of the weld metal from the molten state. Therefore, the staff concludes that the attachment weld for the pressurizer surge and spray nozzle thermal sleeves may be susceptible to cracking as a result of PWSCC, and that the applicant's supplemental AMR for the pressurizer thermal sleeves needs to be revised to include cracking as an applicable effect for the components.

**FPL Response:**

This response was provided to the NRC in FPL letter L-2003-070, dated March 28, 2003. In response to a conference call with the NRC staff on April 23, 2003, the following additional technical information is provided supporting the basis for conclusions regarding primary water stress corrosion cracking (PWSCC) of the pressurizer thermal sleeves having a seam weld (i.e., manufactured from plate material).

Thermal sleeves are included in the design of the pressurizer surge and spray nozzles and are designed to protect these nozzles from thermal shock. Since the thermal sleeves are not part of the nozzle pressure boundary, their failure would not affect the pressure boundary intended function of these nozzles. However, the thermal sleeves are included in the fatigue analyses of the pressurizer surge and spray nozzles and these analyses have been identified as a time-limited aging analysis (TLAA) and dispositioned in LRA Subsection 4.3.1 (page 4.3-2). Accordingly, the thermal sleeves are considered to be within the scope of license renewal, pursuant to 10 CFR 54.4(a)(2) and require an aging management review.

The pressurizer surge and spray nozzle thermal sleeves are fabricated from Alloy 600 and are exposed to an environment of treated water – primary. The only aging effect requiring evaluation for the thermal sleeves is cracking. Cracking due to stress corrosion or primary water stress corrosion was determined not to be an aging effect requiring management based on the design/fabrication of the sleeves. The thermal sleeves for Units 1 and 2 are constructed from either Alloy 600 pipe or rolled Alloy 600 plate material with a longitudinal seam weld. The sleeves are then machined, inserted into their respective nozzles, and expanded to secure them in place. There are no thermal sleeve attachment welds to the nozzles or any other pressurizer pressure boundary parts. Should cracking of a thermal sleeve longitudinal seam weld occur, the sleeve would spring open relieving the principal stresses and would remain captured by the nozzles. Therefore, the sleeve would continue to perform its intended function. Note that since there is no thermal sleeve weld to the nozzle or any other pressure boundary parts, there is no mechanism for the propagation of a crack to impact pressure boundary intended function. As mentioned above, cracking due to fatigue has been identified as a TLAA and is addressed analytically in LRA Subsection 4.3.1. Accordingly, there are no aging effects requiring management for the thermal sleeves.

Note that this conclusion is consistent with that included NUREG-1801, "Generic Aging Lessons Learned (GALL) Report." Pressurizer thermal sleeves are included in Chapter IV of the GALL Report, Item C2.5.5. As indicated in the GALL Report table, the aging effect/mechanism identified for the thermal sleeves is cumulative fatigue damage/fatigue. The GALL Report further states that fatigue is a TLAA for the period of extended operation and further refers to NUREG-1800,

"Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants," Section 4.3 "Metal Fatigue" for acceptable methods for meeting the requirements of 10 CFR 54.21(c)(1). No additional aging effects are identified in the GALL Report for pressurizer thermal sleeves.

Conclusion

Based on the above, FPL requests that Open Item 3.1.2.2-1 be closed.

**FPL Response Supplemental information:**

In response to a conference call with the NRC staff on April 23, 2003, the following additional technical information is provided supporting the basis for conclusions regarding potential primary water stress corrosion cracking (PWSCC) of the pressurizer thermal sleeves having a seam weld (i.e., manufactured from plate material).

As indicated in the response to SER Open Item 3.1.2.2-1 above, the Units 1 and Unit 2 pressurizer nozzle thermal sleeves are either fabricated from Alloy 600 pipe or are rolled from Alloy 600 plate material and seam welded. Specifically, the spray nozzle thermal sleeves are made from pipe, while the surge nozzle thermal sleeves are made from plate material. Due to their welded construction, the aging management review of the surge nozzle thermal sleeves identified their susceptibility to cracking due to PWSCC. However, this aging management review concluded that should cracking of the thermal sleeve longitudinal seam weld occur due to PWSCC, it would not impact the intended function of the sleeve.

PWSCC is intergrannular in nature and therefore, results in a very tight crack geometry. The principle driving force for fluid flow through any through-wall crack in the thermal sleeve would be the differential pressure across the face of the sleeve created by the difference in density between the process fluid and the fluid in the annular space between the sleeve OD and the nozzle. The localized crack geometry when coupled with the very small differential pressure across the face of the sleeve would result in only minor fluid flow. This fluid flow would not be significant in comparison to the equalization holes (three 1/4 inch and two 3/16 inch diameter holes) existing in the thermal sleeve design. These equalization holes provide a total flow area of 0.203 $in^2$. The thermal analysis of the surge nozzle did not specifically model these holes, but assumed natural convection between the thermal sleeve and the nozzle.

In the highly unlikely case that the thermal sleeve longitudinal seam weld was to crack along its entire length, the weld could fail. The sleeve would tend to spring open at the seam to relieve the principal residual stresses, but would remain captured by the nozzle and retainer pins at the sleeve upper end. Because the thermal sleeve is radially restrained/supported at three locations along its length (inlet, the expanded area, and outlet), the potential gap developed at the weld seam during pressurizer steady state (653°F) or hot water insurge/outsurge conditions would be small. This gap is only 0.006 inches maximum at the location below the thermal sleeve expanded area. It opens to up to 0.063 inches at the upper end of the nozzle, and reaches its maximum opening of 0.100 inches within the pressurizer above the nozzle. See Table 3.1.2.2-1.1 below. The additional flow area created by the weld seam gap adjacent to the nozzle during these conditions is 0.032 $in^2$ below the expanded area and 0.340 $in^2$ above the expanded area adjacent to the nozzle.

However, during transients which result in a cold water insurge condition into the pressurizer, the thermal sleeve weld seam gap will open further due to the combined effect of circumferential shrinkage and the residual stresses tending to maintain the sleeve in contact with the nozzle ID. The pressurizer is affected by a number of insurge transients that have been evaluated in the pressurizer stress report. The most significant one is a reactor trip and loss of load transient, with a

minimum temperature of 536°F. Under this limiting transient condition (involving a 117°F temperature differential) the weld seam gap could open 0.035 inches below the thermal sleeve expanded area, 0.097 inches within the nozzle above the expanded area, and reach a maximum opening of 0.133 inches within the pressurizer above the nozzle. The flow area created by the weld seam gap adjacent to the nozzle during these conditions is 0.250 $in^2$ below the expanded area and 0.658 $in^2$ above the expanded area adjacent to the nozzle. See Table 3.1.2.2-1.1 below.

**TABLE 3.1.2.2-1.1**

**Effect of Weld Residual Stresses on Cracked Thermal Sleeve Seam Weld**

| Sleeve Temp. °F | Crack Opening @ Rolled Area in. | Crack Opening @ Nozzle Blend Radius in. | Crack Opening Below Expanded Area in. | Max. Crack Opening Above Nozzle, in. | Limiting Crack Area Adjacent to Nozzle $in.^2$ |
|---|---|---|---|---|---|
| 653 | 0.001 | 0.063 | 0.006 | 0.100 | 0.340 |
| 536 | 0.033 | 0.097 | 0.035 | 0.133 | 0.658 |

The effect of flow through the crack in the thermal sleeve would not have a large effect on the thermal stresses in the pressurizer surge nozzle. However, since the potential crack flow areas exceed the total equalization hole flow area, a bounding analysis has been performed to demonstrate that the nozzle stresses are acceptable. An evaluation of the local effects would require a complex structural and hydraulic model that would consider the effects of fluid mixing and temperature distribution adjacent to the nozzle. To bound the effects, an analysis of the nozzle without the thermal sleeve was conducted. A two dimensional axi-symmetric finite element model was utilized to determine the thermal stresses in the pressurizer surge nozzle at the same locations evaluated in the original pressurizer stress report for Unit 2 (Note: Unit 2 design is identical to Unit 1). Unit 2 was selected based upon a more modern stress analysis and more complete availability of stress report details. In one analysis, thermal stresses are determined using the same thermal boundary conditions that included the thermal sleeve in the pressurizer stress report. A second thermal stress analysis was conducted with the thermal sleeve removed, utilizing forced convection heat transfer coefficients applied directly to the nozzle, in the absence of the thermal sleeve. The thermal stress analysis was conducted in all regions behind the thermal sleeve with the controlling inside surface location being at the nozzle blend radius regions. The fatigue usage factors at this limiting inside surface location increased from 0.002 to 0.0070. At the vessel-to-nozzle weld outside surface, the usage factor increased from 0.018 to 0.020. These are still well below 1.0 and provide ample margin to account for environmental effects.

The results of this analysis demonstrate that the additional flow and convective heat transfer through the gap of a completely cracked thermal sleeve seam weld is accommodated by the significant margin in the existing design.

Additionally, the current analysis of record, which was performed in 1993 to address NRC Bulletin 88-11 (Pressurizer Surge Line Thermal Stratification), determined that the limiting location for the nozzle (based upon stress and fatigue usage factor) is at the surge nozzle to piping weld located upstream of the thermal sleeve. Thus, the limiting location receives no benefit from the thermal sleeve.

Therefore, based upon the above analysis, it is concluded that an Aging Management Program is not required for the Units 1 and 2 pressurizer nozzle thermal sleeves, and that the Units 1 and 2 pressurizer nozzle thermal sleeves will continue to perform their intended function during the period of extended operation.