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

FPL

December 13, 2002

L-2002-239
10 CFR 50.90

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

RE: St. Lucie Units 1 and 2
Docket Nos. 50-335 and 50-389
Proposed License Amendments
Request for Additional Information Response on Risk-Informed One
Time Increase in Integrated Leak Rate Test Surveillance Interval

Pursuant to 10 CFR 50.90 on August 15, 2002, Florida Power & Light Company (FPL) submitted requested to amend Facility Operating Licenses DPR-67 and NPF-16 for St. Lucie Units 1 and 2. The proposed amendments revise Unit 1 and Unit 2 Technical Specifications Section 6.8.4.h, Containment Leakage Rate Testing Program, to allow a one time 5-year extension to the current 10-year test interval for the containment integrated leak rate test (ILRT). St Lucie has implemented the 10 CFR 50, Appendix J, Option B performance-based containment leak rate test program.

The proposed changes were submitted on a risk-informed basis as described in Regulatory Guide (RG) 1.174, *An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis.* The proposed changes to extend the ILRT surveillance interval are justified based on a combination of risk informed analysis and assessment of the containment structural condition utilizing ILRT historical results and containment inspection programs. The risk aspects of the justification have been prepared by the Combustion Engineering Owners Group (CEOG) and are presented in a joint applications report (JAR), WCAP–15691, *Joint Applications Report for Containment Integrated Leak Rate Test Interval Extension*, Revision 2, June 2002. Revision 2 of WCAP-15691 was submitted to the NRC for review by CEOG letter CEOG-02-125 dated June 14, 2002. A brief description and history of St. Lucie Unit 1 and Unit 2 ILRT testing results and the containment inspection program are discussed in the CEOG report with a more detailed description provided in this submittal.

During a conference call with the NRC on October 29, 2002, the NRC staff requested FPL to provide additional information in support of the NRC review of the proposed license amendments.

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Attachment 1 provides the additional information requested by the NRC on October 29, 2002 for containment inspectable area. Attachment 2 provides the additional information on the latent containment corrosion risk sensitivity. Attachment 3 provides additional information on the quality of the St. Lucie probabilistic risk assessment (PSA). The no significant hazard evaluation that was submitted by FPL letter L-2002-143 remains valid and unchanged.

In accordance with 10 CFR 50.91 (b)(1), a copy of the proposed amendments is being forwarded to the State Designee for the State of Florida.

Approval of these proposed license amendments is requested by January 31, 2003 to support the spring St. Lucie Unit 2 refueling outage (SL2-14). Please issue the amendments to be effective on the date of issuance and to be implemented within 60 days of receipt by FPL. Please contact George Madden at 772-467-7155 if there are any additional questions about this submittal.

Very truly yours,

Donald E. Jernigan
Vice President
St. Lucie Plant

DEJ/GRM

Attachments

cc: Mr. William A. Passetti, Florida Department of Health

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

Donald E. Jernigan being first duly sworn, deposes and says:

That he is Vice President, St. Lucie Plant, for the Nuclear Division of Florida Power & 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.

Donald E. Jernigan

STATE OF FLORIDA

COUNTY OF ST LUCIE

Sworn to and subscribed before me

this 13 day of December, 2002
by Donald E. Jernigan, who is personally known to me.

Leslie J. Whitwell
Name of Notary Public - State of Florida

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

(Print, type or stamp Commissioned Name of Notary Public)

ATTACHMENT 1

Background Information

and

Relative Inspectable Area of Containment

ATTACHMENT 1

Background

During telephone conference on October 29, 2002 the NRC requested information regarding the following:

1. In order to determine whether the leakage from the uninspectable area is large enough to be detected by ILRT, provide the total accessible surface area of the metal containment to be examined (surface area should be a percentage of the entire surface area and not just what is accessible).

2. Inspections of some reinforced and steel containment buildings (e.g., North Anna, Brunswick, D.C. Cook, and Oyster Creek) have indicated degradation from the uninspectable (embedded) side of the steel shell and liner of primary containments. The major uninspectable areas of the St. Lucie Units 1 and 2 containments are part of the steel shell embedded in the basemat and the inaccessible areas on both sides of the cylinder and dome. Address how potential leakage, due to age related degradation from these uninspectable areas, is factored into the risk assessment in support of the requested ILRT interval extension from 10 to 15 years.

3. Issues with St. Lucie PSA quality, related to support of risk based submittals, were originally identified in relation to a separate risk based ISI submittal. Provided that the aging analysis demonstrates acceptable results, it may not be necessary to associate a response to these issues with the ILRT interval extension submittal. However, the staff will require that the PSA quality questions be addressed by one of these two submittals.

To be more specific, given the examples provided, the aging issue deals with the potential for a corrosion mechanism to progress to the point at which a leak path would be created in the containment vessel. This in turn is expected to be based on the accessibility of the containment surface to inspection and the likelihood that this failure could go undetected.

The first question is addressed in this attachment. The second question is addressed in Attachment 2. The response to issues related to PSA quality in Question 3 has been recently completed and is included as Attachment 3.

St. Lucie Containment Design

The containment vessel, including all its penetrations, is a low leakage steel shell designed to withstand a postulated design basis accident (DBA) and to confine the radioactive materials that could be released by accidental loss of integrity of the reactor coolant pressure boundary. The containment vessel is a right circular cylinder (approximately 2 inches thick) with hemispherical dome (approximately 1 inch thick) and ellipsoidal bottom (approximately 2 inches thick). It houses the reactor vessel, the reactor coolant system piping and pumps, the steam generators, the pressurizer and the pressurizer quench tank, and other branch connections of the reactor coolant system including the safety injection tanks. The containment vessel penetrations include a construction hatch, a maintenance hatch, a personnel air lock, and escape air lock and various sized penetration nozzles. The containment vessel is also equipped with a dome inspection walkway, access ladder and a circular crane girder with a crane rail attached to the shell of the vessel. The reinforced concrete shield building encloses the containment vessel.

An annular space is provided between the walls and domes of the containment vessel and the shield building in order to permit construction operations and in-service inspection, and to filter any leakage from containment during a loss of coolant accident (LOCA) to minimize dose consequences.

The containment vessel is an independent freestanding structure with a net free volume of approximately 2.5E6 cubic feet. The containment vessel is rigidly supported at its base near the elevation of its bottom spring line. The concrete base was placed after the cylindrical shell and the ellipsoidal bottom were constructed and post weld heat treated. Both the shield building and the containment vessel are supported on a common foundation mat. With the exception of the concrete placed underneath and near the knuckles at the sides of the vessel, there are no structural ties between the containment vessel and the shield building above the foundation slab. Therefore, there is virtually unlimited freedom for differential movement between the containment vessel and the shield building above the top of the concrete base at elevation 23 feet. Concrete floor fill is placed above the ellipsoidal shell bottom, after the vessel was post weld heat treated, to anchor the vessel.

The cylindrical portion of the steel containment shell has a minimum thickness of 1.92 inches on an inside radius of 70 feet. The polar crane girder support plates are welded to the shell at approximately six feet on center. Except for some miscellaneous platform framing and some minor seismic restraints, no major floor framing or seismic restraint supports are attached to the shell. Immediately below the crane girder, a heating and ventilating duct for the containment ring header, approximately five feet wide by five feet deep and running the entire containment circumference, is structurally supported at 30 places and attached to the shell by means of welded clips. The containment shell is also used to support temporary construction loads from the pedestal cranes.

The 1.92-inch minimum shell plate thickness increases to a minimum of four inches adjacent to all penetrations and openings. The inside radius of the hemispherical dome is 70 feet with a dome plate 0.96 inches thick connected to the cylindrical portion of the shell at the tangent line by means of a full penetration weld. The containment spray piping is attached to the dome by means of welded clips as are the dome inspection walkway and platforms. The containment vessel is protected from external missiles by the shield building. The primary and secondary shield walls and other containment internal structures provide protection from internal missiles.

The lower portion of the steel containment vessel is in contact with the concrete on both sides below the 23-foot elevation level except for a small area at the upper interface where an expansion material is used. Since concrete acts to protect steel in contact with it, there is little likelihood of corrosion occurring in the lower section of the steel vessel. During inspection of the expansion material, the areas of the containment vessel at this interface were determined to be the area most affected by corrosion. This area has been evaluated on both units (see discussion in the original FPL submittal L-2002-143) and continues to be inspected in accordance with the St. Lucie ISI-IWE inspection program plan and the evaluation requirements performed under the site corrective action program.

Inspectable Area

Approximately 80 percent of the steel containment vessel is exposed to permit visual inspection. The 20 percent that is inaccessible for visual inspection include the area beneath the concrete floor and a small area around the fuel transfer tube. The relative surface areas are approximated using St. Lucie Plant drawings, St. Lucie Plant UFSARs, and CRC Standard Mathematical Tables.

Accessible Area

Hemispherical dome area = $2\pi Rh = 2\pi(70 \text{ feet})(70 \text{ feet}) = 30{,}788$ square feet

The cylinder conservatively includes the area protected by ethafoam at the concrete metal interface (4-foot depth which starts 1 foot from bottom of cylinder and goes 3 feet into ellipsoidal bottom head).

Cylinder area = $2\pi Rh = 2\pi(70 \text{ feet})(127+3 \text{ feet}) = 57{,}177$ square feet

The total accessible area is 87,965 square feet.

Inaccessible Area

The lower ellipsoidal head may be approximated by one-half of an oblate spheroid less the surface area of a cylinder of the height of the ethafoam included above.

Spheroid = $2\pi a^2 + \pi(b^2/\varepsilon \ln(1+ \varepsilon/1- \varepsilon) = 2\pi(70)^2 + \pi[(35)^2/0.866)] \ln(1+ 0.866/1- 0.866)$

a = major semiaxis = 70 feet
b = minor semiaxis = 35 feet
ε = eccentricity = $(a^2 - b^2)^{1/2} / a = 0.866$

Spheroid/2 = area of lower elliptical shell = 21,246 square feet

Ethafoam area = $2\pi Rh = 2\pi(70)(3)$ = 1319 square feet

Total inaccessible area is 19,927 square feet

Percent accessible = [87,965/(87,965 + 19,927)] x 100 = 81.5%

This approximation is the same for both St. Lucie Unit 1 and Unit 2.

Industry Corrosion Events

Two corrosion events have occurred in the industry that have resulted in a through-wall condition for the metal liner of reinforced concrete containments. There are no reported incidents in which the thicker free standing type steel containment vessel has exhibited a through-wall condition. The events pertaining to the metal liner are summarized below.

On September 22, 1999, North Anna Unit 2 experienced through-wall corrosion of the metal liner. The corrosion appeared to have initiated from a piece of lumber imbedded in the concrete behind the liner plate.

On April 27, 1999, inspection at Brunswick 2 discovered two through-wall holes and pitting in the drywell shell. The through-wall condition was believed to have originated from the coated (visible) side.

It should be noted that neither of these events is specifically applicable to the free standing containment design of St. Lucie Units 1 and 2. Unlike the previously considered containment structure, the St. Lucie metal vessel is surrounded by a shield building with an annular space between them which permits a general visual inspection of the containment exterior surface. The containment metal is substantially thicker (2 inches thick as opposed to 1/4 inch thick) and the outer surface, which is also coated, is in a dry protected air space. In addition, under normal operating conditions, the containment exterior surface is inherently warmer than its surrounding environment preventing condensation on the surface and thus minimizing the potential for a viable corrosion mechanism.

Even presuming that a corrosion induced flaw were to breach the containment it would not initially allow a path of sufficient size to produce a large early release. The only conceivable corrosion mechanism which could lead to a through wall condition of this type of containment is a pitting type corrosion which results in a small leading edge producing a small orifice. Leakage of this magnitude would be contained by the shield building and filtered by the shield building ventilation system.

Therefore, it should be considered that the potential for large early release factor (LERF) is dependent upon containment pressurization propagating a small pre-existing through-wall flaw or near minimum wall flaw produced by the aforementioned corrosion mechanism.

St. Lucie Inspection Program

The St. Lucie containment vessel is examined in accordance with the requirements of ASME Code Section XI, Subsection IWE, the plant protective coatings program, and Technical Specifications. These inspection processes are described as follows.

The Containment Inservice Inspection Program at St. Lucie Units 1 and 2 is described in detail in ISI/IWE-PSL-1/2-PROGRAM, *Metal Containment Inservice Inspection Program*, which provides the rules and requirements. The specific areas and components scheduled for inspection in accordance with the program are provided in ISI/IWE-PSL-1-PLAN, *ASME Section XI, Subsection IWE Containment Building Metal Containment Inservice Inspection Plan for St Lucie Unit 1*, and ISI/IWE-PSL-2-PLAN, *ASME Section XI, Subsection IWE Containment Building Metal Containment Inservice Inspection Plan for St Lucie Unit 2*. The program requirements include inspection of containment surfaces, pressure retaining welds, bolting, seals, gaskets, and moisture barriers using visual, surface, and volumetric techniques as required. Examinations that detect flaws or evidence of degradation shall be documented through the condition report process and evaluated in accordance with the requirements IWE-3000. Personnel performing NDE are qualified and certified in accordance with IWA-2300 of the 1992 Edition with 1992 Addenda of ASME Section XI and implemented by CSI-QI-9.1, *Qualification and Certification of Nondestructive Examination Personnel.*

The IWE program performs inspection of the entire accessible interior surface of the containment in each of 3 periods within a 10-year surveillance interval. The 100% general surface area inspection for the first period on Unit 1 was completed April 2001. The 100% general surface area inspection was completed for the first period in April 2000 and second period in November 2001 on Unit 2. One-third of the moisture barriers at the concrete floor to vessel interface on both sides of containment is inspected during each period. To date, 2/3 of the Unit 1 moisture barrier and 1/3 of the Unit 2 moisture barrier have been inspected. Unit 2 will be 2/3 complete following the upcoming spring 2003 refueling outage (SL2-14).

Inspection results indicate that no significant corrosion effects have been experienced on the containment vessels. At the moisture barrier interface, there have been small areas of surface corrosion and minor pitting detected. However, it does not represent an issue considering the available design margin. A more detailed description was provided in the original proposed license amendments.

During activities that require repair of the containment vessel coatings, ASME Section XI, Subsection IWE, requires visual exams to assess the condition of the vessel metal surface for evidence of flaking, blistering, peeling, discoloration, and other signs of distress. Prior to any repair, NDE personnel perform an inspection to assess the condition of the base material. Following completion of coating repairs, a final inspection is performed by NDE personnel to determine acceptability of the final condition and to act as a reference for future inspections. Using the most recent Unit 1 outage as an example, approximately 25 of these inspections were performed. There has been no indication of containment vessel metal degradation on either unit resulting from these types of inspections.

The Protective Coatings Program at St. Lucie requires that a walkdown of the containment interior be performed each refueling outage by the FPL coatings specialist and engineering personnel to inspect any existing areas of non-qualified coatings and to determine any other areas in need of repair. Personnel familiar with the ASTM coatings standards, in accordance with plant procedures inspect the accessible exterior containment surface. Portions of the upper exterior containment vessel surface are not accessible for inspection due the unavailability of sufficient installed ladders or platforms and so the containment external surface above the floor is not inspected each outage. Inspections of the upper exterior surfaces of both containments have been performed during previous outages. Inspection of the upper section of the exterior side of the containment vessel identified no degraded areas and no potential means by which corrosion would be promoted such as moisture sources or equipment interface. Those areas identified by inspection which do not meet acceptance criteria are evaluated and scheduled for repair as necessary. Following repairs, containment vessel coatings are re-examined upon completion by certified NDE examiners and the as-left condition documented. This allows identification of any potential for containment vessel degradation. As previously stated, there have been no indications of significant degradation of the containment vessel base metal.

General visual inspections of both sides of the accessible containment vessel surface and the shield building are performed as required by Technical Specifications in accordance with Quality Instruction QI 10-PR/PSL-5, *Technical Specification Surveillance Inspection of Reactor Building*. Results of these inspections have not revealed any additional conditions to that already noted other than minor concrete spalling of the shield building.

Attachment 2

Liner Corrosion Risk Assessment

Liner Corrosion Request:

Inspections of some reinforced and steel containments (e.g., North Anna, Brunswick, D.C. Cook, and Oyster Creek) have indicated degradation from the uninspectable (embedded) side of the steel shell and liner of primary containments. The major uninspectable areas of the St. Lucie Units 1 and 2 containments are part of the steel shell embedded in the basemat and the inaccessible areas on both sides of the cylinder and dome. Address how potential leakage, due to age related degradation from these uninspectable areas, are factored into the risk assessment in support of the requested ILRT interval extension from 10 to 15 years.

Response:

The following approach was used to assess the change in large early release factor (LERF) as a result of undetected containment vessel corrosion. Previously evaluated intact sequences were evaluated against the likelihood of an undetected through-wall corrosion event and the result used to establish the potential increase in LERF. The following are issues factored into the analysis:

- Differences between the concrete encased containment lower head and the exposed containment cylinder and dome.
- Historical probability of corrosion producing a through-wall flaw without prior detection.
- Aging impact on failure probability.
- Leakage dependency on containment pressure.
- Probability that visual inspections will be effective in detection.

It should be emphasized that this approach to estimating the additional potential for LERF due to corrosion is a conservative bounding exercise for the type of containment structure utilized for St. Lucie Units 1 and 2. Based on the lack of failure history, mechanical, and environmental differences which resist or preclude previously identified failure mechanisms, and the considerably greater time for discovery that exists due the order of magnitude thicker steel structure a more detailed analysis is likely to conclude that the risk component was not of significant magnitude to warrant augmenting existing risk parameters.

<u>Assumptions</u>

1. A half failure is conservatively assumed for the concrete concealed lower containment vessel due to the lack of any identified failures for this part of the structure. (See Table 1, Step 1.)

2. The success data was limited to 5.5 years to reflect the years since September 1996 when 10 CFR 50.55a started requiring visual inspection. Additional time was not utilized to limit the aging impact of the corrosion issue even though inspection had been required and performed under other programs prior to this date and there is no evidence that liner corrosion issues were identified. (See Table 1, Step 1.)

3. The potential for corrosion induced flaw likelihood is assumed to double every 5.5 years. This is based on reasonable statistical judgement and is consistent with prior analysis accepted by the NRC. It is included to address the likelihood of corrosion as the liner ages. Sensitivity studies are included that addresses doubling this rate every 10 years and every 2 years. (See Table 1, Steps 2 and 3, and Tables 5 and 6.)

4. The likelihood of a breach in the steel vessel due to corrosion produced localized wall thinning or flaw is a function of the containment pressure. It should be considered that in the case of a free standing steel containment vessel with a nominal 2-inch thickness that significant deterioration would be detected. However, it may be conservatively considered that the potential exists for a localized corrosion mechanism to produce a small (less than LERF) through-wall or near through-wall flaw prior to detection. Failure at lower pressures is proportionately unlikely. However, at the point of postulated containment failure, a through-wall breach would be statistically certain. Probability values were assumed as 0.1% at 20 psia and 100% at 110 psia (based on IPE level 2 containment failure pressure) with intermediate failure probabilities determined through logarithmic interpolation. Credit for the shield building is taken only in that a leak of magnitude that remains less than LERF is contained and does not contribute to the risk parameter. Sensitivity studies are included that decrease and increase the probability of containment failure at 20 psia anchor point by a factor of 10. (See Table 4 for sensitivity studies)

5. The probability of minimum wall flaw resulting in containment breach in the concrete enclosed lower containment vessel is considered to be 10 times less likely than the exposed containment cylinder and dome regions. (See Table 1, Step 4.)

6. A five percent visual inspection detection failure likelihood, given the flaw, is visible and a total detection failure likelihood of 10% is used. (See Table 1, Step 5.) Sensitivity studies are included that evaluate total detection failure likelihood of 5 percent and 15 percent. (See Table 4 for sensitivity studies.)

7. The total CDF is included in determining the potential for large early releases. This approach avoids a detailed analysis of containment failure timing and operator recovery actions. The CDFs from internal events of 2.99E-5/Yr for Unit 1 and 2.44 E-5/Yr for Unit 2 are based on a conservative model. Although CDF from external events has not been calculated using a more detailed and realistic approach, it is estimated to be less than that of the internal events.

Table 1-Liner Corrosion Base Case

Step	Description	Containment Cylinder and Dome 80%		Containment Basemat 20%	
1	**Historical Liner Flaw Likelihood** Failure data: Containment location specific Success data: Based on 70 steel-lined containments and 5.5 years since the 10 CFR 50.55a requirement for periodic visual inspection of containment surfaces	Events:2 (Brunswick & North Anna 2) 2/(70*5.5)=5.2E-3		Events: 0 Assume half a failure 0.5/(70*5.5)=1.3E-3	
2	**Aged Adjusted Liner Flaw Likelihood** During 15-year interval, assumed failure rate doubles every 5 years (14.9% increase per year). The average for fifth to tenth year was set to the historical failure rate (See Table 5 for an example)	Year	Failure Rate	Year	Failure Rate
		1 avg 5-10 15	2.1E-3 5.2E-3 1.4E-2	1 avg 5-10 15	5.0E-4 1.45E-3 4.0E-3
		15-year avg 6.45E-3		15-year avg 1.8E-3	
3	**Increase in Flaw Likelihood Between 3 and 15 years** Uses aged adjusted liner flaw likelihood (Step 2), assuming failure rate doubles every 5 years. (See Tables 5 and 6)	8.97%		2.5%	
4	**Likelihood of Breach in Containment given Liner Flaw** The upper end pressure is consistent with St. Lucie Probabilistic Risk Assessment (PSA) Level 2 analysis. 0.1% is assumed lower end. Intermediate failure likelihoods are determined through logarithmic interpolation. The basemat is assumed to be 1/10 of the cylinder/dome analysis	Pressure (psia) 20 58.7 (Design) 110	Likelihood of Breach 0.1% 1.95% 100%	Pressure (psia) 20 58.7 (Design) 110	Likelihood of Breach 0.01% 0.195% 10%
5	**Visual Inspection Detection Failure Likelihood**	10% 5% failure to identify that the flaw is not visible (not through-cylinder but could be detected by ILRT). All events detected through visual inspection. 5% visible failure detection is a conservative assumption.		100% Cannot be visually inspected.	
6	**Likelihood of Non-detected Containment Leakage.** (Steps 3*4*5)	0.017% 8.97%*1.95%*10%		0.0048% 2.5%*0.195%*100%	

The total likelihood of the corrosion-induced, non-detected containment leakage is the sum of Step 6 for the containment cylinder and dome and the containment basemat.

Total Likelihood of Non-Detected Containment Leakage = 0.017% + 0.0048% = 0.022%

The increase in LERF associated with the liner corrosion issue is estimated as:

Increase in LERF (ILRT 3 to 15 years) = 0.022% * 2.99E-5 per year = 6.6E-9 per year for Unit 1.

Increase in LERF (ILRT 3 to 15 years) = 0.022% * 2.44E-5 per year = 5.4E-9 per year for Unit 2.

<u>Change in Risk</u>

The risk of extending the ILRT from 3 in 10 years to 1 in 15 years is evaluated by considering the following elements.

1. The risk associated with the failure of the containment due to a pre-existing containment breach at the time of core damage (Class 3 events).
2. The risk associated with liner corrosion that could result in an increased likelihood that containment over-pressurization events become LERF events.
3. The likelihood that improved visual inspections (frequency and quality) will be effective in discovering liner flaws that could lead to LERF.

These elements are presented in detail in the following discussion.

<u>Pre-Existing Containment Breach</u>

The original submittal addressed Item 1. The submittal calculated the increase risk using a new CEOG methodology and a previously NRC-approved methodology. Table 2a and Table 2b summarize the risk increase associated with extending the Type A test from 3 in 10 years to 1 in 15 years for St. Lucie Unit 1 and St. Lucie Unit 2, respectively.

Table 2a Risk Increase Associated with Pre-Existing Containment Breach, St. Lucie Unit 1

Method	LERF Increase	Person-REM/yr Increase	Percentage Increase in Person-REM/yr
CEOG Method	1.4E-8	10.26	1.14%
NRC Approved Method	9.4E-8	1.13	0.18%

Table 2b-Risk Increase Associated with Pre-Existing Containment Breach, St. Lucie Unit 2

Method	LERF Increase	Person-REM/yr Increase	Percentage Increase in Person-REM/yr
CEOG Method	1.0E-8	7.41	0.71%
NRC Approved Method	7.7E-8	0.93	0.11%

<u>Liner Corrosion</u>

Table 3a and Table 3b summarize the risk increase with liner corrosion included for St. Lucie Unit 1 and St. Lucie Unit 2, respectively.

Table 3a-Risk Increase Including Liner Corrosion Impact for St Lucie Unit 1

Method	LERF Increase	Person-REM/yr Increase	Percentage Increase in Person-REM/yr
CEOG Method	1.4E-8	10.26	1.14%
CEOG Method with Liner Corrosion	2.1E-8	10.51	1.17%
NRC-Approved Method	9.4E-8	1.13	0.18%
NRC-Approved Method with Liner Corrosion	1.1E-7	1.18	0.19%

Table 3b-Risk Increase Including Liner Corrosion Impact for St Lucie Unit 2

Method	LERF Increase	Person-REM/yr Increase	Percentage Increase in Person-REM/yr
CEOG Method	9.6E-9	7.41	0.71%
CEOG Method with Liner Corrosion	1.5E-8	7.61	0.73%
NRC-Approved Method	7.7E-8	0.93	0.107%
NRC-Approved Method with Liner Corrosion	8.25E-8	0.96	0.111%

Visual Inspections

The original submittal did not fully address the benefit of the Subsection IWE visual inspections. Visual inspections following the 1996 change in the ASME Code are believed to be more effective in detecting flaws. In addition, the flaws that are of concern for LERF are considerably larger than are those of concern for successfully passing the ILRT. Integrated leakage rate test failures have occurred even though visual inspections have been performed. However, the recorded ILRT flaw sizes for these failed tests are much smaller than that for LERF. Therefore, it is likely that future inspections would be effective in detecting the larger flaws associated with a LERF.

Impact of Improved Visual Inspections

The raw data for both the CEOG method and previously approved NRC method is contained in NUREG-1493. This containment performance data is pre-1994. In 1996, the USNRC endorsed the use of Subsection IWE to ASME Section XI which provided detailed requirements for in service inspection of containment structures. Inspection and attendant requirements for examination, evaluation, repair, and replacement activities of the MC type containment, in accordance with 10CFR 50.55a, involves consideration of potential corrosion areas. Based on a more rigorous, structured inspection process, it should be considered that the detection of flaws after 1996 is more likely than that prior to inception of IWE requirements, and contributes to a more effective coatings program, further reducing the likelihood of corrosion induced failure.

Visual inspection improvements directly reduce the delta LERF increases as calculated in the CEOG method and NRC-approved method. The increased inspection frequency reduces the delta LERF as calculated by both the CEOG and NRC-approved methods. Table 7 illustrates the benefit of visual inspection improvements on the delta LERF calculations.

If the improved inspections (additional inspection, improved effectiveness, and larger flaw size) were 90% effective in detecting the flaws in the visible regions of the containment (5% for failure to detect and 5% for flaw not detectable [not-through-wall]), then the increase ILRT LERF frequency could be reduced by 23.5%. See Tables 7a and 7b for additional sensitivity cases. This indicates significant margin exists for the estimated LERF increase.

Sensitivity Studies

The following cases were developed to gain an understanding of the sensitivity of this analysis to the various key parameters. For this sensitivity study, the values performed for Unit 2 are used for Unit 1 as the containment liner contribution is the same for both units.

Table 4-Liner Corrosion Sensitivity Cases

Age (Step 2)	Containment Breach (Step 4)	Visual Inspection & Non-Visual Flaws (Step 5)	Likelihood Flaw Is LERF	LERF Increase
Base Case Doubles every 5 years	Base Case 1.95/0.19	Base Case 10%	Base Case 100%	Base Case 5E-9
Doubles every 2 years	Base	Base	Base	6E-8
Doubles every 10 years	Base	Base	Base	2E-9
Base	Base point 10 times lower (0.52/0.05)	Base	Base	1E-9
Base	Base point 10 times higher (7.2/0.72)	Base	Base	2E-8
Base	Base	5%	Base	3E-9
Base	Base	15%	Base	7E-9
		Lower Bound		
Doubles every 10 years	Base point 10 times lower (0.524/0.05)	5%	10%	4E-1 1
		Upper Bound		
Double every 2 years	Base point 10 times higher (7.2/0.72)	15%	100%	3E-7

Table 5-Flaw Failure Rate as a Function of Time

Year	Containment	Basemat
0	1.79E-03	5.00E-04
1	2.06E-03	5.74E-04
2	2.36E-03	6.60E-04
3	2.71E-03	7.58E-04
4	3.12E-03	8.71E-04
5	3.58E-03	1.00E-03
6	4.11E-03	1.15E-03
7	4.72E-03	1.32E-03
8	5.43E-03	1.52E-03
9	6.23E-03	1.74E-03
10	7.16E-03	2.00E-03
11	8.22E-03	2.30E-03
12	9.45E-03	2.64E-03
13	1.09E-02	3.03E-03
14	1.25E-02	3.48E-03
15	1.43E-02	4.00E-03
15-year average	6.45E-03	1.80E-03
Delta 1 in 3 to 1 in 15	8.97E-02	2.50E-02

Table 6-Cumulative Failure Probability

Years	Containment	Basemat
1 to 3	0.71%	0.20%
1 to 10	4.15%	1.16%
1 to 15	9.68%	2.70%

Δ = 9.68% - 0.71% = 8.97% (delta between 1 in 3 years to 1 in 15 years), for containment

Δ = 2.7% - 0.2% = 2.5% (delta between 1 in 3 years to 1 in 15 years), for basemat

Table 7a-Benefit of Visual Inspection Improvements for St. Lucie Unit 1

Factor Improvement Due to Visual Inspections	Reduction in Delta LERF	NRC Approved Method Delta LERF	NRC Approved Method w/Liner Corrosion Considered Delta LERF	CEOG Method Delta LERF	CEOG Method w/Liner Corrosion Considered Delta LERF
Pre-1996 Inspection Approach (Base Case)	0%	9.40E-08	9.95E-08	1.40E-08	1.95E-08
Post-1996 with Visual Inspections Perfectly Accurate	80%	1.88E-08	1.99E-08	2.80E-09	3.89E-09
Post-1996 with Visual Inspections 95% Accurate	76.00%	2.26E-08	2.39E-08	3.36E-09	4.67E-09
Post-1996 with Visual Inspections 95% Accurate and 5% Chance of Undetectable Leakage	72.00%	2.63E-08	2.78E-08	3.92E-09	5.45E-09
Post-1996 with Visual Inspections 80% Accurate and a 5% Chance of Undetectable Leakage	60.00%	3.76E-08	3.98E-08	5.60E-09	7.78E-09

Table 7b-Benefit of Visual Inspection Improvements for St. Lucie Unit 2

Factor Improvement due to Visual Inspections	Reduction in Delta LERF	NRC Approved Method Delta LERF	NRC Approved Method w/Liner Corrosion Considered Delta LERF	CEOG Method Delta LERF	CEOG Method w/Liner Corrosion Considered Delta LERF
Pre-1996 Inspection Approach (Base Case)	0%	7.70E-08	8.25E-08	1.00E-08	1.55E-08
Post-1996 with Visual Inspections Perfectly Accurate	80%	1.54E-08	1.65E-08	2.00E-09	3.09E-09
Post-1996 with Visual Inspections 95% Accurate	76.00%	1.85E-08	1.98E-08	2.40E-09	3.71E-09
Post-1996 with Visual Inspections 95% Accurate and 5% Chance of Undetectable Leakage	72.00%	2.16E-08	2.31E-08	2.80E-09	4.33E-09
Post-1996 with Visual Inspections 80% Accurate and a 5% Chance of Undetectable Leakage	60.00%	3.08E-08	3.30E-08	4.00E-09	6.18E-09

It is noted that the CDF used in the current analysis is conservative. In addition, the large early release used is also conservative. Based on a more recent review of the degraded core phenomena modeling, the LERF for the St. Lucie large dry containment is on the order of 0.01. The LERF values used in this license submittal are approximately an order of magnitude higher (see Table 2, Class 3a and 3b of FPL letter L-2002-143[1]: 0.085, the sum of 0.064 and 0.021 was used). If the CDF of external events is assumed to be as high as that of the internal events, the increase in the risk may be bounded by doubling the calculated values. The total risk increase (including the external events and the conservatism in both the CDF and LERF modeling) associated with the one time extension of the ILRT interval from 3 in 10 years to 1 in 15 years is approximately a factor of 5 lower than that estimated (a factor of 10 reduction from conservatism of LERF and CDF divided by a factor of 2 from the external event assumption).

Conclusion

Considering increased frequency of visual inspections and the benefit of improved visual inspections post-1996, the increase in risk is considered to be less than 1 E-7 for

[1] L-2002-143, St. Lucie Units 1 and 2, Docket Nos. 50-335 and 50-389 Proposed License Amendments: Risk Informed One Time Increase in Integrated Leak Rate Test Surveillance Interval

LERF. Changes less than 1 E-7 are considered small per Regulatory Guide 1.174. The one-time extension of the ILRT interval from 3 in 10 years to 1 in 15 years is considered an acceptable risk increase.

Attachment 3

PSA Quality Related Issues

Note: No formal written question was issued. However, the PSA quality in general similar to that raised for RI-ISI was discussed during the conference call on October 29, 2002. The same questions related to the PSA quality for RI-ISI are summarized below. It is concluded that the PSA model used for the St. Lucie ILRT is robust with respect to the ILRT application. The weaknesses stated in the SE are briefly outlined below.

PSA Quality Related Request 1

Identify the version of the Probabilistic Safety Assessment (PSA) model that was used for the RI-ILRT application and when it was last updated. Include when, and which version, of your PSA has been peer reviewed by the Combustion Engineering Owner's Group.

Response 1:

The version of the Level 1 model used for input to the RI-ILRT submittal is dated March 2001. The version of the Level 2 update is dated May 2001.

The St. Lucie CEOG peer review was conducted the week of May 20, 2002. The model reviewed by the peer review team was the draft version of a 2002 update. The latest Level 2 update, dated May 2001, validates that the one percent early containment failure assumption used for the LERF calculations is bounding.

PSA Quality Related Request 2:

The staff evaluation (SE) report on the St. Lucie Individual Plant Examination (IPE), dated July 21, 1997, concluded that the IPE met the intent of GL 88-20. The SE also stated that "the staff identified weaknesses in the front-end, HRA and back-end portions of the IPE which, we believe, limit its future usefulness." The weaknesses stated in the SE are briefly outlined below. Explain how each of the weakness has been removed by modifications to the PRA or otherwise addressed during the RI-ISI evaluation.

Some initiating event frequencies appeared low and some initiating event frequencies which relied on generic values should have received a plant-specific analysis.

Response 2:

Data update has been performed since the IPE. The data update included re-quantification of the LOCA initiating event (IE) frequencies based on a CEOG technical position paper. Initiating event fault trees were also developed for loss of component cooling water (CCW), loss of intake cooling water (ICW), loss of turbine cooling water (TCW), loss of DC bus, and loss of instrument air. Plant specific data was used for other initiating events where available.

There is no significant difference between the total CDF due to the change of the initiating event frequencies. It is judged that this IE data issue does not have a significant impact on the results and conclusions for the ILRT application.

PSA Quality Related Request 3:

Some pre-initiator human actions appeared in dominant accident sequences, an unexpected and uncommon result. It appears that a more detailed analysis of pre-initiator human actions may appropriately reduce the human error probabilities (HEPs) for these events, thus reducing the likelihood that excessively conservative HEPs may distort the risk profile.

Response 3:

Screening values have been used in all updates to date. It is judged that the use of unrefined pre-initiator screening values is conservative for the ILRT application, as a more refined HRA may reduce HEP and thus lower the CDF.

PSA Quality Related Request 4:

It was not clear what basis was used to determine which post-initiator human actions were quantified with a time-independent technique and those post-initiator actions that were quantified with a time-dependent technique. Three post-initiator human actions (initiating once-through cooling, manually initiating recirculation actuation components following loss of the automatic signal, and securing the reactor coolant pumps after loss of seal cooling) are relatively short time frame events. Failure to consider time in these events might lead to unrealistic values.

Response 4:

No changes to the HRA analysis to address this issue have been implemented for the PSA updates to date. The St. Lucie IPE SER states that "the HEPs for the events modeled as slips were not unreasonable and several of the events modeled in this way still show up as being important. Therefore, there is no reason to believe that the approach necessarily precluded detection of HRA related vulnerabilities."

A sensitivity study was performed on these actions. The results indicate that this HRA issue does not have a significant impact on the results and conclusions for the ILRT application.

PSA Quality Related Request 5:

The time-dependent human actions used likelihood indices at their default values. Therefore, the resulting human error probabilities may be generic rather than plant-specific.

Response 5:

No changes to the HRA to address this issue have been implemented for the PSA updates to date. The St. Lucie IPE SER states that in general, the way in which the SAIC time-dependent method was applied in the IPE did not appear to violate its basic tenets and that resulting HEPs would not be considered unusual. The SER also states that most of the HEP values themselves would not suggest that identification of human action vulnerabilities was precluded.

A sensitivity study was performed using updated HEPs for events previously quantified as time-independent. The methodology used to calculate the revised HEPs addresses plant specific factors.

The process for evaluating individual human interactions breaks down the detection, diagnosis, and decision-making aspects into different failure mechanisms, with causes of failure delineated for each. Eight different potential failure mechanisms are identified:

- Availability of information
- Failure of attention
- Misread/miscommunicate data
- Information misleading
- Skip a step in procedure
- Misinterpret instruction
- Misinterpret decision logic
- Deliberate violation

A relatively simple decision tree is used for each of these mechanisms. Each of these decision trees identifies performance shaping factors that could cause the relevant mechanism to lead to failure to initiate the proper action. The analyst selects branch points in the decision trees that correspond to the aspects of the interaction being analyzed (e.g., the number and quality of cues for the operators, the ease of use of the procedures, etc.). For each outcome in the decision trees, there is a nominal probability of failure.

Depending on the failure cause, certain recovery mechanisms may come into play. The potential for recovery may arise as follows:

- due to self-review by the operator initially responsible for the misdiagnosis or error in decision-making, as additional cues become available or additional procedural steps provide opportunity to review actions that have been taken and the resulting effects on the plant;
- as a result of review by other crew members who would be in a position to recognize the lack of proper response;
- by the STA, whose review might identify errors in the response;

- by the technical support center (TSC) when it is staffed and actively involved in reviewing the situation; and
- by oncoming crewmembers when there is a shift turnover (when the time window is very long).

Thus, after processing each of the decision trees to arrive at estimates for the basic failure mechanisms, the analyst must identify and characterize the appropriate recovery factors.

There are other considerations besides time that affect the treatment of the non-recovery potential. These included the degree to which new or repeated cues and recurring procedural steps would give rise to considering the action that had not been successfully taken.

Another element represents failure to implement the action correctly, given that the decision is made to initiate the action. A basic task analysis is performed to identify the essential steps that must be accomplished to implement a decision. The corresponding failures to perform them properly are noted. These failures are then quantified.

In considering the execution errors, three levels of stress were identified: optimal, moderately high, and extremely high. Optimal stress would apply for actions that are part of a normal response to a reactor trip, and for which the operators would be alert. Moderately high stress would apply when the operators are responding to unusual events, including multiple failures. Extremely high stress would apply for scenarios in which there is a significant threat, such as the potential that core damage is imminent if the actions are not successful, or when actions must be accomplished under significantly less than optimal conditions.

The execution errors may be subject to review and recovery as well. This is particularly true for actions taken in the control room, where additional observers may be able to identify the need for corrective action. As in the case of the initiation errors, a set of guidelines for considering review and recovery by other crewmembers has been developed.

Based on the discussion above, it can be seen that the revised HEPs used in the sensitivity study takes into account plant specific factors.

It is judged that this HRA issue does not have a significant impact on the results and conclusions for the ILRT application.

PSA Quality Related Request 6:

An additional sensitivity analysis should have been performed regarding the probability of in-vessel recovery since the licensee assumed a very high probability of in-vessel recovery due to ex-vessel cooling.

Response 6:

It is recognized that there are variations in the probability of in-vessel recovery. For the ILRT applications, other conservatism embedded in the Level 2 model with respect to other dominant early containment failure mechanisms (e.g., direct containment heating, steam explosion, and the vessel acting like a rocket) outweigh this issue. The revised Level 2 analysis incorporating the insights after the IPE submittal was made indicates that the large early containment failure probability, assuming 25% of ex-vessel cooling, is less than 1%.

In conclusion, there is conservatism in the PSA model used for the ILRT applications. In addition, there is significant margin between the calculated risk increase and acceptance criteria. The PSA quality is thus judged to be sufficient and PSA model robust for the ILRT application.