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

FPL

July 30, 2003

L-2003-187
10 CFR 50.55a

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

Re: St. Lucie Unit 1
Docket No. 50-335
Inservice Inspection Program
Second Ten-Year Interval
Relief Request 19 Risk-Informed Inservice Inspection Program

Pursuant to 10 CFR 50.55a (a)(3)(i), Florida Power and Light Company (FPL) requests approval of Relief Request 19 for the third ten-year inservice inspection interval. The Inservice Inspection (ISI) Program currently requires inspections on piping in accordance with the requirements of the ASME Boiler and Pressure Vessel Code Section XI, 1989 Edition as required by 10CFR50.55a. St. Lucie Unit 1 is currently in the third inspection interval as defined by the ASME Section XI Code for Program B.

The objective of this submittal is to request a change to the ISI Program plan for Class 1 piping only, through the use of a Risk-Informed Inservice Inspection (RI-ISI) Program. The risk-informed process used in this submittal is described in Westinghouse Owners Group WCAP-14572, Revision 1-NP-A, Westinghouse Owners Group Application of Risk-Informed Methods to Piping Inservice Inspection Topical Report. As a risk-informed application, this submittal meets the intent and principles of Regulatory Guide (RG) 1.174, *An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis*, and RG 1.178, *An Approach for Plant-Specific Risk-Informed Decision Making: Inservice Inspection of Piping*. In accordance with 10 CFR 50.55a (a)(3)(i), FPL has determined that the proposed alternatives would provide an acceptable level of quality and safety.

FPL requests approval of the enclosed relief request by January 31, 2004 to support its use during the spring 2004 refueling outage (SL1-19). If you have any questions or require additional information, please contact George Madden at 772-467-7155.

Very truly yours,

William Jefferson, Jr.
Vice President
St. Lucie Plant

WJ/GRM

Enclosure

A047

St. Lucie Unit 1
Third Inspection Interval
10CFR50.55a Relief Request Number 19

1. ASME Code Component(s) Affected

All St. Lucie Unit 1 Class 1 Pressure Retaining Similar and Dissimilar Metal Piping Welds.

2. Applicable Code Edition and Addenda

ASME Code, Section XI, 1989 Edition with no Addenda.

3. Applicable Code Requirement

Exam Cat.	Item No.	Examination Description
B-F	B5.40	Pressurizer - NPS 4 or larger, Nozzle-to-Safe End Butt Welds
	B5.50	Pressurizer - Less than NPS 4, Nozzle-to-Safe End Butt Welds
	B5.130	Piping- NPS 4 or Larger, Dissimilar Metal Butt Welds
	B5.140	Piping- Less than NPS 4, Dissimilar Metal Butt Welds
B-J	B9.11	Piping- NPS 4 or Larger, Circumferential Welds
	B9.12	Piping- NPS 4 or Larger, Longitudinal Welds
	B9.21	Piping- Less than NPS 4, Circumferential Welds
	B9.22	Piping- Less than NPS 4, Longitudinal Welds
	B9.31	Piping- Branch Pipe Connection Welds, NPS 4 or Larger
	B9.32	Piping- Branch Pipe Connection Welds, Less than NPS 4
	B9.40	Piping- Socket Welds

4. Reason for Request

Pursuant to 10 CFR 50.55a(a)(3)(i), FPL requests to revise the St. Lucie Unit 1 ISI Program for Class 1 piping only, through the use of the Risk-Informed Inservice Inspection Program (RI-ISI), Attachment 1, as an alternative to the current requirements of Class 1 examination Categories B-F and B-J as specified in Table IWB-2500-1 of the 1989 Edition of ASME Section XI.

The proposed revision to the current ISI program, for Class 1 piping only, is based on the risk-informed process described in Westinghouse Owners Group WCAP-

14572, Revision 1-NP-A, *Westinghouse Owners Group Application of Risk-Informed Methods to Piping Inservice Inspection Topical Report.*

5. Proposed Alternative and Basis for Use

Inservice inspections (ISI) are currently performed on piping to the requirements of the ASME Boiler and Pressure Vessel Code Section XI, 1989 Edition as required by 10 CFR 50.55a. St. Lucie Unit 1 is currently in the third inspection interval as defined by the Code for Program B.

ASME Section XI Class 1 Categories B-F and B-J currently contain the requirements for examining (via non-destructive examination (NDE)) Class 1 piping components. This current program is limited to ASME Class 1 piping, including piping currently exempt from requirements. The alternative RI-ISI program for piping is described in WCAP-14572, Revision 1-NP-A. FPL will substitute the Class 1 RI-ISI for the current examination program on piping.

Other non-related portions of the ASME Section XI Code will be unaffected.

WCAP-14572, Revision 1-NP-A, provides the requirements defining the relationship between the risk-informed examination program and the remaining unaffected portions of ASME Section XI. The attached Risk-Informed Inservice Inspection Program supports the conclusion that the proposed alternative provides an acceptable level of quality and safety.

Additionally, this submittal meets the intent and principles of Regulatory Guides 1.174 and 1.178.

6. Duration of Proposed Alternative

This request for relief is applicable to the St. Lucie Unit 1 Third 10-year Inservice Inspection Interval, which started on February 11, 1998 and ends on February 10, 2008.

7. Precedents

St. Lucie Nuclear Plant, Unit 2, Docket No. 50-389, received approval to implement a Risk-Informed Inservice Inspection Program utilizing the same methodology by SER dated April 25, 2003 (TAC No. MB5698).

St. Lucie Unit 1
Third Inspection Interval
10CFR50.55a Relief Request Number 19

8. References

Attachment 1- Florida Power and Light Company, St. Lucie Unit 1, Risk-Informed Inservice Inspection Piping Program Submittal Using the Westinghouse Owners Group (WOG) Methodology (WCAP-14572, Revision 1-NP-A, February 1999)

Florida Power and Light Company

St. Lucie Unit 1

Risk-Informed Inservice Inspection Piping Program Submittal

Using the Westinghouse Owners Group (WOG) Methodology

(WCAP-14572, Revision 1-NP-A, February 1999)

June 2003

RISK-INFORMED INSERVICE INSPECTION PROGRAM PLAN

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1. INTRODUCTION/RELATION TO NRC REGULATORY GUIDE RG-1.174

1.1 Introduction

Inservice inspections (ISI) are currently performed on piping to the requirements of the ASME Boiler and Pressure Vessel Code Section XI, 1989 Edition as required by 10 CFR 50.55a. St. Lucie Unit 1 is currently in the third inspection interval as defined by the Code for Program B.

The objective of this submittal is to request a change to the ISI program plan for Class 1 piping only through the use of a risk-informed inservice inspection (RI-ISI) program. The risk-informed process used in this submittal is described in Westinghouse Owners Group WCAP-14572, Revision 1-NP-A, *Westinghouse Owners Group Application of Risk-Informed Methods to Piping Inservice Inspection Topical Report*, (referred to as WCAP-14572, A-version for the remainder of this document).

As a risk-informed application, this submittal meets the intent and principles of Regulatory Guides 1.174 and 1.178. Further information is provided in Section 3.10 relative to defense-in-depth.

1.2 PRA Quality

The St. Lucie Unit 1 Probabilistic Safety Assessment (PSA) baseline model was used to evaluate the consequences of pipe ruptures. The base core damage frequency (CDF) and the base large early release frequency (LERF) are 1.45E-05 and 3.43E-06, respectively.

The version of the Level 1 model used for input to the RI-ISI submittal is dated February 1999. The version of the Level 2 evaluation used is dated May 2001. The revision and applications of the PRA models and associated databases are handled as "Quality Related" under the FPL 10 CFR Appendix B Quality Assurance Program. Administrative controls include written procedures, independent review of all model changes, data updates, and risk assessments performed using PSA methods and models. Risk assessments are performed by one PSA engineer, independently reviewed by another PSA engineer, and approved by the department head or designee. The PSA group falls under the FPL Engineering Quality Instructions (QI) with written procedures derived from those QIs. Procedures, risk assessment documentation, and associated records are controlled and retained as QA records.

Since the approval of the St. Lucie Individual Plant Examination (IPE), the FPL Reliability and Risk Assessment Group (RRAG) has maintained the PSA models consistent with the current plant configuration such that they are considered "living" models. The PSA models are updated for different reasons, including plant changes and modifications, procedure changes, accrual of new plant data, discovery of modeling errors, advances in PSA technology, and issuance of new industry PSA standards. The update process ensures that the applicable changes are implemented and documented timely so that risk analyses performed in support of plant operation reflect the plant configuration, operating philosophy, and transient and component failure history. The PSA maintenance and update process is described in FPL RRAG Standard, *PSA Update and Maintenance Procedure*. This standard defines two different types of periodic updates: 1) a data analysis update, and 2) a model update. The data analysis update is performed at least every five years. Model updates consist of either single or multiple PSA changes and are performed at a frequency dependent on the estimated impact of the accumulated changes. Guidelines to determine the need for a model update are provided in the standard.

The safety evaluation (SE) report on the St. Lucie IPE, dated July 21, 1997, concluded that the St. Lucie IPE met the intent of NRC Generic Letter 88-20. The SE also stated that "the staff identified weaknesses in the front-end, HRA [human reliability analysis] and back-end portions of the IPE which, we believe, limit its future usefulness." The weaknesses stated in the SE are briefly outlined below. A discussion of each weakness as related to the RI-ISI evaluation is provided below:

1. *Identified IPE Weakness: Some initiating event frequencies appeared low and some initiating event frequencies which relied on generic values should have received a plant-specific analysis.*

   Discussion of this SE identified weakness related to the RI-ISI evaluation:

   Data update has been performed since the IPE and before the RI-ISI evaluation. The data update included re-quantification of the loss of cooling accident (LOCA) initiating event (IE) frequencies based on a Combustion Engineering Owners Group (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.

   The impact of the IEs on the RI-ISI is judged to be small as RI-ISI focuses on Class 1 piping and the LOCA frequencies are estimated using probabilistic fracture mechanics. As a sensitivity study, the loss of CCW, loss of ICW, loss of TCW, loss of DC bus, and loss of instrument air IE frequencies were changed to reflect values obtained from quantifying each of the IE fault trees. These revised IE frequencies, along with revised human error probabilities (HEP) (discussed below), were used to re-quantify the "Change in CDF" and conditional core damage probability (CCDP) values used to derive the relative risk of each segment.

There is no significant difference between the sensitivity study values for "Change in CDF" and CCDP and those used for the submittal. It is judged that this IE data issue does not have a significant impact on the results and conclusions for the RI-ISI application.

2. <u>*Identified IPE Weakness:*</u> *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.*

   Discussion of this SE identified weakness related to the RI-ISI evaluation:

   Screening values have been used in all updates to date. The LOCA initiator related cutset files generated in support of the RI-ISI submittal were reviewed to determine the Fussel-Vesely (FV) values for the dominant pre-initiator actions. The largest FV value noted was approximately 3E-02. Only three other cases had values slightly greater than 1E-02. The risk reduction worth for the dominant pre-initiator would thus only be 3%. The potential impact on CDF due to more detailed analyses of the pre-initiators would thus be less than 3% for the dominant contributor and less than 1% for most.

   It is judged that the use of unrefined pre-initiator screening values does not have a significant impact on the results and conclusions for the RI-ISI application.

3. <u>*Identified IPE Weakness:*</u> *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.*

   Discussion of this SE identified weakness related to the RI-ISI evaluation:

   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."

For Class 1 piping RI-ISI applications, the use of a different HRA method is not expected to affect the conditional core damage probability given pipe breaks. As discussed for weakness (1) above, a sensitivity study was performed using updated IE frequencies and updated HEPs. The specific HRA events identified in the IPE review and other potentially significant HRA events that were originally quantified using a time-independent technique were re-quantified as time-dependent actions. The resulting HEPs along with the revised IE frequencies discussed for weakness (1) above were used to re-quantify the "Change in CDF" and CCDP values used to derive the relative risk of each segment.

There is no significant difference between the sensitivity study values for "Change in CDF" and CCDP and those used for the submittal. It is judged that this HRA issue does not have a significant impact on the results and conclusions for the RI-ISI application.

4. *Identified IPE Weakness: 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.*

   Discussion of this SE identified weakness related to the RI-ISI evaluation:

   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.

   As discussed for weakness (3) above, 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/miscommunicated 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 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 RI-ISI application.

5. <u>Identified IPE Weakness</u>: *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.*

   Discussion of this SE identified weakness related to the RI-ISI evaluation:

   For the Class 1 piping RI-ISI application, conservatism embedded in the IPE with respect to other dominant early containment failure mechanisms (e.g., direct containment heating, steam explosion, and the vessel acting like a rocket) outweigh the risk impact of variations in the probability used for in-vessel recovery. The revised Level 2 analysis, incorporating insights since the IPE submittal, indicates that the large early containment failure probability is less than 1%.

A Combustion Engineering Owner's Group 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 peer review team Facts and Observations (F&Os) were reviewed for potential impact on the RI-ISI submittal results. Some of the F&Os are recommendations related only to documentation improvements and thus have no impact on the PSA results. Other F&Os are not related to LOCA scenarios and have an insignificant impact on the Class 1 piping RI-ISI applications. The rest of the F&Os affecting the CDF results are similar to those weaknesses of the IPE submittal discussed above. The review of the F&Os related to potential model enhancements concluded that the issues addressed by the F&Os would not have a significant impact on the results and conclusions of the RI-ISI evaluation.

The St. Lucie Unit 1 PSA model uses a large fault tree/small event tree method of quantification. Event tree models were developed to define the logic for core damage sequences. The event tree models were converted to equivalent fault tree logic and linked to the frontline and support system fault tree models. The core damage sequence gates were combined into a single-top core damage gate using "OR" logic. The single-top core damage gate was quantified to obtain core damage cutsets in terms of basic events. The core damage cutsets were used to obtain the CDF values. Each quantification involves post-process operations on the quantified "raw" cutsets. Cutsets containing pre-defined mutually exclusive event combinations were removed from the final cutset listing. Finally, recovery events were applied to selected cutsets based on pre-defined recovery rules.

For this RI-ISI application, the impact of pipe breaks were simulated by defining surrogate basic events in the fault tree models and using the events to configure the fault tree models prior to the quantification process. If a pipe break did not result in an initiating event, the appropriate basic event(s) were set to a logical "TRUE" state prior to each fault tree quantification to simulate failure of a mitigation system or function due to the pipe break. If a pipe break resulted in an initiating event, the appropriate basic event(s) were set equal to the initiating event prior to each fault tree quantification to simulate the impact of the pipe break initiating event on mitigation systems or functions. Existing basic events in the model were used as the preferred method of simulating the postulated pipe break. New surrogate basic events were added to the model, as required, to properly simulate the impact of the postulated pipe break when existing events were not adequate.

The Level 2 evaluation determines that for Unit 1, LERF comprises 1% of CDF, except for those degradations that result in the inability to mitigate Steam Generator Tube Ruptures or Interfacing Systems LOCAs.

It is concluded that the St. Lucie PSA method and model would yield meaningful rankings for RI-ISI evaluations when combined with deterministic insights.

2. PROPOSED ALTERNATIVE TO ISI PROGRAM

2.1 ASME Section XI

ASME Section XI Class 1 Categories B-F and B-J currently contain the requirements for examining (via non-destructive examination (NDE)) Class 1 piping components. This RI-ISI program is limited to ASME Class 1 piping, including piping currently exempt from requirements. The alternative RI-ISI program for piping is described in WCAP-14572, A-Version. The Class 1 RI-ISI program will be substituted for the current examination program on piping in accordance with 10 CFR 50.55a(a)(3)(i) by alternatively providing an acceptable level of quality and safety. Other non-related portions of the ASME Section XI Code will be unaffected. WCAP-14572, A-Version, provides the requirements defining the relationship between the risk-informed examination program and the remaining unaffected portions of ASME Section XI.

2.2 Augmented Programs

There are no augmented inspection programs for the St. Lucie Unit 1 Class 1 piping systems.

3. RISK-INFORMED ISI PROCESSES

The processes used to develop the RI-ISI program are consistent with the methodology described in WCAP-14572, A-Version.

The process that is being applied, involves the following steps:

- Scope Definition
- Segment Definition
- Consequence Evaluation
- Failure Assessment
- Risk Evaluation
- Expert Panel Categorization
- Element/NDE Selection
- Implement Program
- Feedback Loop

Deviations

There are two deviations to the process described in WCAP-14572, A-Version:

WCAP-14572 uses the Westinghouse Structural Reliability and Risk Assessment Model (SRRA) to calculate failure rates. Since SRRA is a Westinghouse product and St. Lucie is a CE plant, FPL uses WinPRAISE, a Microsoft Windows based version of the PRAISE code used as the benchmark for SRRA in WCAP-14572 Supplement 1.

In WCAP-14572, selection of elements in Regions 1B and 2 of the Structural Element Selection Matrix shown in Figure 3.7-1 of the WCAP is determined by a statistical evaluation process. Since the statistical model used in the WCAP is a proprietary Westinghouse product and St. Lucie is a CE plant, an alternative selection process was used. The alternative is based on that described in EPRI Topical Report TR-112657 Rev. B-A, approved in a Safety Evaluation Report dated October 28, 1999 and on current ASME Section XI criteria. The alternative process selected 25% of the elements in each High Safety Significance segment. This resulted in the selection of 31.5% of the total population of elements in the High Safety Significance segments.

3.1 Scope of Program

The scope of the piping in this submittal is all Class 1 piping, including piping exempt from current Section XI examination requirements. This piping scope boundary limits the program to consideration of the reactor coolant pressure boundary portions of the CH, RC, and SI systems, including those portions that provide the shutdown cooling function. No Class 1 welds were excluded. The Class 1 piping systems included in the risk-informed ISI program are provided in Table 3.1-1.

3.2 Segment Definitions

Once the scope of the program is determined, the piping for these systems is divided into segments as described in the WCAP, Section 3.3.

The number of pipe segments defined for the Class 1 piping systems are summarized in Table 3.1-1. The as-operated piping and instrumentation diagrams were used to define the segments.

3.3 Consequence Evaluation

The consequences of pressure boundary failures are measured in terms of core damage and large early release frequency. The impact on these measures due to both direct and indirect effects was considered.

A review of the license basis of St. Lucie (Updated Final Safety Analysis Report Amendment No. 19) and the IPE Internal Events Methodology was performed to determine the potential impact of the indirect effects of pipe leak or rupture inside containment. As a result of the review, it was concluded that the containment structure and the safety related components inside containment are adequately protected from pipe failures such that the effects of a failure are limited to direct effects. Table 3.3-1 summarizes the postulated consequences for each system.

3.4 Failure Assessment

Failure estimates were generated utilizing industry failure history, plant specific failure history, and other industry relevant information.

The engineering team that performed this evaluation used WinPRAISE, a Microsoft Windows based version of the PRAISE code used as the benchmark for SRRA in WCAP-14572, Supplement 1. The failure rate for each segment was based on an aggregate condition, utilizing a combination of the highest individual values of each parameter input to the calculation.

Table 3.4-1 summarizes the failure probability estimates for the dominant potential failure mechanism(s)/combination(s) by system. Table 3.4-1 also describes why the failure mechanisms could occur at various locations within the system. Full break cases are shown only when pipe whip is of concern.

No augmented inspections are performed for the Class 1 piping.

3.5 Risk Evaluation

Each piping segment within the scope of the program was evaluated to determine its CDF and LERF due to the postulated piping failure. Calculations were also performed with and without operator action.

Once this evaluation was completed, the total pressure boundary core damage frequency and large early release frequency were calculated by summing across the segments for each system. The results of these calculations are presented in Table 3.5-1. The expected value for core damage frequency due to piping failure both without operator action and with operator action is 9.031E-05/year. The expected value for large early release frequency due to piping failure both without operator action and with operator action is 9.031E-07/year. This evaluation also included a 5th and 95th percentile uncertainty analysis.

The baseline CCDPs for the LOCAs are as follows:

LOCA SIZE	CDF CONTRIBUTION	FREQ	CCDP
SMALL-SMALL LOCA	7.27E-06	3.01E-03	2.42E-03
SMALL LOCA	4.32E-08	2.16E-05	2.00E-03
LARGE LOCA	7.28E-07	5.85E-05	1.24E-02

To assess safety significance, the risk reduction worth (RRW) and risk achievement worth (RAW) importance measures were calculated for each piping segment.

3.6 Expert Panel Categorization

The final safety determination (i.e., high and low safety significance) of each piping segment was made by the expert panel using both probabilistic and deterministic insights. The expert panel was comprised of personnel who have expertise in the following fields; probabilistic safety assessment, inservice examination, nondestructive examination, stress and material considerations, plant operations, plant and industry maintenance, repair, and failure history, system design and operation, and SRRA methods including uncertainty. Maintenance Rule Expert Panel members were used to ensure consistency with the other PSA applications.

The expert panel had the following positions represented during the expert panel meeting.

- Probabilistic Safety Assessment (PSA Engineer)
- Maintenance Rule (Chairman)
- Operations (Senior Reactor Operator)
- Inservice Inspection (ISI&NDE)
- Plant & Industry Maintenance, Repair, and Failure History (System Engineer)
- Materials Engineer
- Stress Engineer

A minimum of four members filling the above positions constituted a quorum. This core team of panel members was supplemented by other experts, including a piping stress engineer, as required for the piping system under evaluation.

The System and Component Engineering Manager is the chairman of the expert panel. The Maintenance Rule Administrator may act as alternate chairman.

Members received training and indoctrination in the risk-informed inservice inspection selection process. They were indoctrinated in the application of risk analysis techniques for ISI. These techniques included risk importance measures, threshold values, failure probability models, failure mode assessments, PSA modeling limitations and the use of expert judgment. Training documentation is maintained with the expert panel's records.

Worksheets were provided to the panel containing information pertinent to the panel's selection process. This information in conjunction with each panel member's own expertise and other documents, as appropriate, was used to determine the safety significance of each piping segment.

Meeting minute records were generated. The minutes included the names of members in attendance and whether a quorum was present. The minutes contained relevant discussion summaries and the results of membership voting.

3.7 Identification of High Safety Significant Segments

The number of high safety significant segments for each system, as determined by the expert panel, is shown in Table 3.7-1 along with a summary of the risk evaluation identification of high safety significant segments.

3.8 Structural Element and NDE Selection

The structural elements in the high safety significant piping segments were selected for inspection and appropriate non-destructive examination methods were defined.

The program being submitted addresses the high safety significant (HSS) piping components placed in Regions 1 and 2 of Figure 3.7-1 and described in Section 3.7.1 in WCAP-14572, A-Version. Region 3 piping components, which are low safety significant, are to be considered in an Owner Defined Program and is not considered part of the program requiring NRC approval. Region 1, 2, 3 and 4 piping components will continue to receive Code required pressure testing, as part of the current ASME Section XI Program. For the 204 piping segments that were evaluated in the RI-ISI program, Region 1 contains 9 segments, Region 2 contains 2 segments, no segments are contained in Region 3, and Region 4 contains 193 segments.

The number of locations to be inspected in applicable HSS segments was determined using a selection process based on that described in EPRI Topical Report TR-112657 Rev. B-A, approved in a Safety Evaluation Report dated October 28, 1999, and on current ASME Section XI criteria. The process selected 25% of the elements in each High Safety Significance segment. This resulted in the selection of 31.5% of the total population of elements in the High Safety Significance segments.

Table 4.1-1 in WCAP-14752, A-Version, was used as guidance in determining the examination requirements for the HSS piping segments. VT-2 visual examinations are scheduled in accordance with the station's pressure test program, which remains unaffected by the risk-informed inspection program.

Additional Examinations

The risk-informed inspection program in all cases will determine through an engineering evaluation the root cause of any unacceptable flaw or relevant condition found during examination. The evaluation will include the applicable service conditions and degradation mechanisms to establish that the element(s) will still perform their intended safety function during subsequent operation. Elements not meeting this requirement will be repaired or replaced.

The evaluation will include whether other elements on the segment or segments are subject to the same root cause and degradation mechanism. Additional examinations will be performed on these elements up to a number equivalent to the number of elements initially required to be inspected on the segment or segments. If unacceptable flaws or relevant conditions are again found similar to the initial problem, the remaining elements identified as susceptible will be examined. No additional examinations will be performed if there are no additional elements identified as being susceptible to the same service related root cause conditions or degradation mechanism. The St. Lucie Unit 1 Risk-Informed Inservice Inspection Program will follow the requirements of 1989 ASME Section XI Code with regard to additional examinations and will complete those sample expansions within the outage they were identified.

3.9 Program Relief Requests

An attempt shall be made to provide a minimum of >90% coverage criteria (per ASME Code Case N-460) when performing an exam. Some limitations will not be known until the examination is performed, since some locations will be examined for the first time by the specified techniques.

In instances where it may be found at the time of the examination that a location does not meet >90% coverage, the process outlined in Section 4.0 (Inspection Program Requirements) of WCAP-14572, A-Version will be followed.

3.10 Change in Risk

The risk-informed ISI program has been done in accordance with Regulatory Guide 1.174, and the risk from implementation of this program is expected to remain constant when compared to that estimated from current requirements.

A comparison between the proposed RI-ISI program and the current ASME Section XI ISI program was made to evaluate the change in risk. The approach evaluated the change in risk with the inclusion of inservice inspections with a "good" probability of detection in the WinPRAISE model and followed the guidelines provided on page 213 of WCAP-14572, A-version.

The results from the risk comparison are shown in Table 3.10-1. As seen from the table, the overall RI-ISI program maintains the risk associated with piping CDF/LERF, with respect to the current Section XI program, while reducing the number of examinations. The primary basis for being able to maintain risk with a reduced number of examinations is that exams are now being placed on piping segments that are high safety significant, and in some cases elements are inspected that are not inspected by NDE in the current ASME Section XI ISI Program.

The reactor coolant piping will continue to receive a system leakage test and visual VT-2 examination as currently required by the Code. Volumetric examinations will also continue on the main reactor coolant piping as part of the RI-ISI program (segments categorized HSS). These locations, which include main loop and pressurizer surge line welds determined by the RI-ISI program for St. Lucie Unit 1, assure that "defense-in-depth" is maintained. No additional inspection locations are required to meet "defense-in-depth."

4. IMPLEMENTATION AND MONITORING PROGRAM

Upon approval of the RI-ISI program, procedures that comply with the guidelines described in WCAP-14572, A-Version, will be prepared to implement and monitor the program. The new program will be integrated into the existing ASME Section XI interval. No changes to the Technical Specifications or the Updated Final Safety Analysis Report are necessary for program implementation.

The applicable aspects of the Code not affected by this change would be retained, such as inspection methods, acceptance guidelines, pressure testing, corrective measures, documentation requirements, and quality control requirements. Existing ASME Section XI program implementing procedures would be retained and would be modified to address the RI-ISI process, as appropriate. Additionally, the procedures will be modified to include the high safety significant locations in the program.

The proposed monitoring and corrective action program will contain the following elements:

A. Identify
B. Characterize

C. Evaluate
   (1) Evaluate, determine the cause and extent of the condition identified
   (2) Evaluate, develop a corrective action plan or plans
D. Decide
E. Implement
F. Monitor
G. Trend

The RI-ISI program is a living program requiring feedback of new relevant information to ensure the appropriate identification of high safety significant piping locations. As a minimum, risk ranking of piping segments will be reviewed and adjusted on an ASME Section XI inspection period basis. Significant changes may require more expedited adjustment as directed by NRC Bulletin or Generic Letter requirements, or by plant specific feedback. The RI-ISI program would be resubmitted to the NRC for approval for:

- Changing from one methodology to another
- Changing scope of application
- Plant-specific impact of revised methodology or safety evaluations
- Industry experience determines that there is a need for significant revision to the program as described in the original submittal for that interval
- Changes that impact the basis for NRC approval in the FPL St. Lucie Unit 1 specific safety evaluation
- ASME Section XI Ten-Year update

5. PROPOSED ISI PROGRAM PLAN CHANGE

A comparison between the RI-ISI program and the current ASME Section XI program requirements for piping is given in Table 5-1. The plant will be performing examinations on elements not currently required to be examined by ASME Section XI. The current ASME Section XI program selects a prescribed percentage of examinations without regard to safety significance. The RI-ISI program focuses examinations on those high safety significant segments and subsequent examinations are required on inspection elements not currently scheduled for examination by the ASME Section XI program.

The program will be started in the second period of the third interval, starting in the outage, which began September 30, 2002. Currently, sufficient exams in the Section XI program have been performed to meet the 16% minimum requirement for the end of the first inspection period of the current interval.

6. SUMMARY OF RESULTS AND CONCLUSIONS

A partial scope Class 1 risk-informed ISI application has been completed for Unit 1. Upon review of the proposed risk-informed ISI examination program given in Table 5-1, an appropriate number of examinations are proposed for the high safety significant segments across the Class 1 portions of the plant piping systems. Resources to perform examinations currently required by ASME Section XI in the Class 1 portions of the plant piping systems, though reduced, are distributed to address the greatest amount of risk within the scope. Thus, the change in risk principle of Regulatory Guide 1.174 is maintained. Additionally, the examinations performed will address specific damage mechanisms postulated for the selected locations through appropriate examination selection and increase volume of examination.

The construction permit for St. Lucie Unit 1 was issued July 1970. The plant is designed to ANSI B31.7, 1969, for the Class 1 piping. Large bore main loop and pressurizer surge line piping is the major contributor to the overall risk of piping pressure boundary failure due to the stress levels and potential transients.

From a risk perspective, the PRA dominant accident sequences include: small LOCA; transients; and loss of offsite power.

For the RI-ISI program, appropriate sensitivity and uncertainty evaluations have been performed to address variations in piping failure probabilities and PRA consequence values along with consideration of deterministic insights to assure that all high safety significant piping segments have been identified.

As a risk-informed application, this submittal meets the intent and principles of Regulatory Guide 1.174.

7.0 REFERENCES/DOCUMENTATION

1. WCAP-14572, Revision 1-NP-A, *Westinghouse Owners Group Application of Risk-Informed Methods to Piping Inservice Inspection Topical Report*, February 1999

2. Calculation Number PSL-BFJR-98-004, Revision 2, *St. Lucie Units 1 & 2 Baseline EOOS Models.*

3. St. Lucie Units 1 & 2 Individual Plant Examination Submittal, Revision 0, dated December 1993.

4. St. Lucie Unit 1 Probabilistic Safety Assessment Update Revision 0, 1997.

5. St. Lucie Unit 1 Updated Final Safety Analysis Report Amendment No. 19

6. Procedure STD-R-002, *Probabilistic Safety Assessment Update and Maintenance Procedure*, Revision 2, Dated July 25, 1996.

Supporting Onsite Documentation

The onsite documentation is contained within the following Engineering Evaluations:

1. PSL-ENG-SEOS-01-017, *St. Lucie Unit 1 Risk-Informed ISI Program Development Analysis*

2. PSL-ENG-SEOS-01-018, *St. Lucie Unit 1 Risk-Informed ISI Program – Failure Analysis*

3. PSL-ENG-SEOS-01-019, *St. Lucie Unit 1 Risk-Informed ISI Program – Consequence Quantification*

Table 3.1-1 System Selection and Segment Definition for Class 1 Piping			
System Description	**PRA**	**Section XI**	**Number of Segments**
CH - Chemical & Volume Control	Yes	Yes	14
RC - Reactor Coolant[1]	Yes	Yes	119
SI - Safety Injection [1,2]	Yes	Yes	71
Total			204

Notes:

1. Includes shutdown cooling flowpaths.
2. Includes flow paths for high pressure safety injection, low pressure safety injection, and the passive accumulator in portions of SI.

Table 3.3-1 Summary of Postulated Consequences by System	
System	**Summary of Consequences**
CH – Chemical & Volume Control	The direct consequences postulated from piping failures in this system are: loss of auxiliary pressurizer spray; loss of one or more trains for charging; and small-small loss of coolant accident (LOCA).
RC – Reactor Coolant	The direct consequences associated with piping failures are: large, small, and/or small-small LOCAs; loss of safety injection tank flow path; loss of cold or hot injection leg flow path; loss of alternate injection flow path; loss of auxiliary pressurizer spray; loss of one or more charging flow paths; and loss of identified instrumentation.
SI – Safety Injection	The direct consequences associated with piping failures are: loss of safety injection tank flow path; loss of low pressure safety injection (LPSI) flowpath; loss of cold or hot leg injection flow path; loss of alternate injection flowpath; piping break outside primary containment; large and/or small-small LOCAs; loss of suction to LPSI pump; loss of identified instrumentation.

Table 3.4-1 Failure Probability Estimates (without ISI)			
System	Dominant Potential Degradation Mechanism(s)/ Combination(s)	Failure Probability Range (Small Leak Probability @ 40 years, no ISI)	Comments
CH	-Fatigue	1.47E-12 – 6.67E-07	The charging path to the applicable RCS loop is potentially susceptible to thermal fatigue.
RC	-Fatigue	1.37E-15 – 1.27E-05	Fatigue at instrument line connections to main loop.
	-Thermal Transients	5.95E-14 – 2.85E-03	Piping where large thermal transients could occur: pressurizer surge line and charging nozzles.
	-Thermal and Vibratory Fatigue	7.13E-07 – 4.48E-05	The piping is located on the RCP pump or seal housing and is potentially subject to vibration.
SI	-Fatigue	5.11E-18 – 2.37E-09	Piping in flow path of injection lines and SIT is potentially susceptible to thermal fatigue.

Table 3.5-1 Number of Segments and Piping Risk Contribution by System (without ISI)					
System	# of Segments	CDF without Operator Action (/yr)	CDF with Operator Action (/yr)	LERF without Operator Action (/yr)	LERF with Operator Action (/yr)
CH	14	3.698E-11	3.151E-13	3.698E-13	3.151E-15
RC	119	9.031E-05	9.031E-05	9.031E-07	9.031E-07
SI	71	5.758E-12	5.758E-12	8.537E-14	8.537E-14
TOTAL	204	9.031E-05	9.031E-05	9.031E-07	9.031E-07

Table 3.7-1 Summary of Risk Evaluation and Expert Panel Categorization Results						
System	Number of segments with any RRW > 1.005	Number of segments with any RRW between 1.005 and 1.001	Number of segments with all RRW < 1.001	Number of segments with any RRW between 1.005 and 1.001 placed in HSS	Number of segments with all RRW < 1.001 selected for inspection	Total number of segments selected for inspection (High Safety Significant Segments)
CH	0	0	14	0	0	0
RC	9	2	108	2	0	11
SI	0	0	71	0	0	0
Total	9	2	193	2	0	11

Table 3.10-1 COMPARISON OF CDF/LERF FOR CURRENT SECTION XI AND RISK-INFORMED ISI PROGRAMS		
Case	Current Section XI	Risk-Informed
CDF No Operator Action	7.75E-05	7.75E-05
• CH	3.67E-11	3.67E-11
• RC	7.75E-05	7.75E-05
• SI	5.76E-12	5.76E-12
CDF with Operator Action	7.75E-05	7.75E-05
• CH	8.86E-14	8.86E-14
• RC	7.75E-05	7.75E-05
• SI	5.76E-12	5.76E-12
LERF No Operator Action	7.75E-07	7.75E-07
• CH	3.67E-13	3.67E-13
• RC	7.75E-07	7.75E-07
• SI	8.53E-14	8.53E-14
LERF with Operator Action	7.75E-07	7.75E-07
• CH	8.86E-16	8.86E-16
• RC	7.75E-07	7.75E-07
• SI	8.53E-14	8.53E-14

Attachment 1
Relief Request Number 19

Table 5-1

**STRUCTURAL ELEMENT SELECTION
RESULTS AND COMPARISON TO ASME SECTION XI
1989 EDITION REQUIREMENTS**

System	Number of High Safety Significant Segments (No. of HSS in Aug. Program / Total No. of Segments in Aug. Program)	Degradation Mechanism(s)	Class	ASME Code Category	Weld Count		ASME XI Examination Methods (Volumetric (Vol) and Surface (Sur))		RI-ISI	
					Butt	Socket	Vol & Sur	Sur Only	SES Matrix Region	Number of Exam Locations
CH	0	Thermal Fatigue	1	B-F	3	0	0	3	-	0
				B-J	13	157	0	22		
RC	11 (0/0)	Thermal Fatigue, Thermal Transients, Vibration Fatigue	1	B-F	21	0	12	9	1, 2	4 volumetric
				B-J	156	17	33	18		20 volumetric
SI	0	Thermal Fatigue	1	B-F	6	0	6	0	-	0
				B-J	285	15	69	22		
TOTAL	11 (0/0)		CL. 1	B-F	30	0	18	12		4 NDE
				B-J	454	189	102	62		20 NDE
			TOTAL		484	189	120	74		24 NDE

Summary: Current ASME Section XI selects a total of 120 non-destructive exams (surface only exams not included), while the proposed RI-ISI program selects a total of 24 non-destructive exams. This results in a 80.0% reduction of non-destructive exams.

General Note:
System pressure test requirements and VT-2 visual examinations shall continue to be performed in ASME Class 1 systems.