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

FPL

January 4, 2006

L-2005-263
10 CFR 50.4
10 CFR 50.55a

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

Re: St. Lucie Unit 2
Docket Nos. 50-389
In-Service Inspection Plans
Third Ten-Year Interval
Repair of Alloy 600 Small Bore Nozzles Without Flaw Removal
Unit 2 Relief Request 5 Revision 1

Pursuant to 10 CFR 50.55a (a)(3)(ii), Florida Power & Light Company (FPL) requests extension of the third ten-year in-service inspection (ISI) interval Unit 2 Relief Request 5 via Revision 1. FPL determined pursuant to 10 CFR 50.55a (a)(3)(ii) that compliance with the specified requirements would result in hardship or unusual difficulty without a compensating increase in the level of quality and safety. The Unit 2 third interval Relief Request 5 was previously submitted by FPL letter L-2003-285 on November 21, 2003, supplemented by FPL letters L-2004-065 on March 24, 2004 and L-2004-100 on April 20, 2004 and approved for one operating cycle by NRC letter dated May 18, 2004.

Approval of the attached revision to the relief request for the remainder of the inspection interval is requested to support the upcoming St. Lucie Unit 2 refueling outage (SL2-16 is currently scheduled to begin in April, 2006). Please contact Ken Frehafer at 772-467-7748 if there are any questions about this submittal.

Very truly yours,

William Jefferson, Jr.
Vice President
St. Lucie Plant

Attachment

WJ/KWF

A047

Proposed Alternative in Accordance with 10CFR 50.55a(a)(3)(ii)

Hardship or Unusual Difficulty without Compensating
Increase in Level of Quality or Safety

"REPAIR OF ALLOY 600 SMALL BORE NOZZLES WITHOUT FLAW REMOVAL"

1. ASME Code Component(s) Affected

Small bore alloy 600 nozzles welded to the reactor coolant piping hot legs and pressurizer and alloy 600 heater sleeves welded to the pressurizer
St. Lucie (PSL) Unit 2
Reactor Coolant Piping Nozzle Details
FPL Drawing Numbers: 2998-18705 Rev. 1, 2998-18706 Rev. 1
Pressurizer Nozzle Details
FPL Drawing Numbers: 2998-19321 Rev. 0, 2998-19466 Rev. 0, 2998-19467 Rev. 0
Pressurizer Heater Sleeves
FPL Drawing Numbers: 2998-16985 Rev.3

2. Applicable Code Edition and Addenda

ASME B&PV Code Sect. XI, "Rules for In-Service-Inspection of Nuclear Power Plant Components" 1999 Edition through the 2000 Addenda

3. Applicable Code Requirement

Pursuant to 10 CFR 50.55a (a)(3)(ii) FPL requests an alternative to the requirements of ASME B&PV Code, Section XI, paragraph IWB-3132.2 "Acceptance by Repair/Replacement Activity A component whose volumetric or surface examination detects flaws that exceed the acceptance standards of Table IWB-3410-1 is unacceptable for continued service until the additional examination requirements of IWB-2430 are satisfied and the component is corrected by a repair/replacement activity to the extent necessary to meet the acceptance standards of IWB-3000."

4. Reason for Request

Small bore nozzles were welded to the interior of the hot leg of the reactor coolant piping and pressurizer and heater sleeves were welded to the interior of the pressurizer during fabrication of the piping and pressurizer. Industry experience has shown that cracks may develop in the nozzle base metal, heater sleeve base metal or in the weld metal joining the nozzles to the reactor coolant pipe and pressurizer and also weld metal joining the heater sleeves to the pressurizer and lead to leakage of the reactor coolant fluid. The cracks are believed to be caused by primary water stress corrosion cracking (PWSCC). The exact leak path, through the weld or through the base metal or through both, cannot be determined.

To remove all possible leak paths requires accessing the internal surface of the reactor coolant piping and pressurizer and grinding out the attachment weld and any remaining nozzle base metal. Such an activity results in high radiation exposure to the personnel involved which is considered a hardship. Grinding within the components also exposes personnel to safety hazards. Additionally, grinding on the internal surface of the reactor coolant piping increases the possibility of introducing foreign material that could damage the fuel cladding. The NRC approved topical report, Reference 1, and the following section "Proposed Alternative and Basis for Use" show that there is "no compensating increase in the level of quality or safety" resulting from removal of the cracked metal.

5. Proposed Alternative and Basis for Use

PROPOSED ALTERNATIVE

All the alloy 600 small bore nozzles on the St. Lucie Unit 2 hot leg piping and on the pressurizer have been replaced with alloy 690 nozzles. No pressurizer heater sleeves have been replaced.

The original weld or base metal was not and will not be corrected. The nozzles were and will be repaired by relocating the attachment weld from the inside surface of the pipe or pressurizer to the outside surface of the pipe or pressurizer.

Nozzle welds on the hot leg piping and pressurizer have been repaired using the "half-nozzle" technique and the "sleeve" technique. The status of alloy 600 small bore nozzle repairs at Saint Lucie Unit 2 is shown in TABLE 1.

In the "half-nozzle" technique, see FIGURE 1 weld joint designs A and B, the nozzles are cut outboard of the partial penetration weld between the nozzles and pipe or pressurizer wall, approximately midwall. The cut sections of the alloy 600 nozzles are replaced with short sections (half-nozzles) of alloy 690 which are then welded to the outside surfaces of the pipe or pressurizer. The remainders of the alloy 600 nozzles, including the partial penetration welds, remain in place.

In the "sleeve" technique, see FIGURE 1 weld joint designs C and D, the entire nozzle is removed by machining and the bore diameter is slightly enlarged. Subsequently an alloy 690 sleeve is inserted into the bore and rolled into place. The end of the sleeve at the interior surface of piping or pressurizer is either roll expanded or welded to the interior surface of the piping or pressurizer essentially eliminating corrosion of the carbon steel by stopping the replenishment of borated solution in contact with the carbon steel. An alloy 690 nozzle is inserted into the sleeve and the nozzle and sleeve are welded to the exterior of the piping or pressurizer.

The weld joint designs shown in FIGURE 1 are illustrative only. The drawings are not to scale and the drawings are not definitive.

The nozzles on the pressurizer and several nozzles on the hot leg piping are welded to pads which were deposited on the exterior surface of the pressurizer or piping using a temper bead technique.

The pressurizer heater sleeves will be repaired using the "half-nozzle" technique. The replacement sleeves will be welded to pads to be deposited on the pressurizer lower head using a temper bead technique.

The remnant material (weld metal, nozzles and heater sleeves) will not receive additional examination. The new pressure boundary welds, on the exterior surface of the piping and pressurizer, will be examined in accordance with the applicable requirements of the ASME Boiler and Pressure Vessel Code Sections III and XI.

BASIS FOR USE

WCAP-15973-P-A Revision 0, Reference 1, Section 2.3, evaluates the effect of component corrosion resulting from primary coolant in the half nozzle crevice region between the remnant alloy 600 nozzles and replacement alloy 690 nozzle. The WCAP, in Section 2.5, also evaluates the effect of component corrosion resulting from primary coolant in a confined crevice, like the sleeve repair, where the volume of the solution is such that the solution can not be replenished.

In the "half-nozzle" repair, a small gap remains between the remnants of the alloy 600 nozzles and heater sleeves and the new alloy 690 nozzles and heater sleeves. As a result, primary coolant (borated water) will fill the crevice between the nozzles and the pipe and pressurizer and between the heater sleeve and pressurizer lower head. Low alloy and carbon steels used for reactor coolant systems components are clad with stainless steel to minimize corrosion resulting from exposure to borated primary coolant. Since the crevice regions are not clad, the low alloy and carbon steels are exposed to borated water. Therefore, the corrosion rates addressed in the "half nozzle" repair will utilize the corrosion analysis in Reference 1, Section 2.3.

The "sleeve" repair was not specifically evaluated in Reference 1. However, Reference 1, Section 2.5, provides an alternate estimate of carbon and low alloy steel corrosion. The corrosion rate previously described is applicable to the carbon and low alloy steel exposed to bulk solutions of boric acid and not to solutions confined in a crevice where the volume of the solution is such that the solution cannot be replenished or refreshed. The geometry of the "sleeve" repair results in a tight crevice between the alloy 690 sleeve and the base metal of the hot leg piping or pressurizer which is equivalent or even tighter than that evaluated in Reference 1, Section 2.5. Therefore, the corrosion rates shown in Reference 1, Section 2.5 will be used to evaluate the "sleeve" repair.

Reference 1, demonstrates that the carbon and low alloy steel Reactor Coolant System components at St. Lucie Unit 2 will not be unacceptably degraded by general corrosion as a result of the implementation of replacement of small diameter alloy 600 nozzles and heater sleeves. Although some minor corrosion may occur in the crevice region of the replaced nozzles and sleeves, the degradation will not proceed to the point where ASME B & PV Code requirements will be exceeded before the end of plant life, including the period of extended operation. Further, available laboratory data and field experience indicate that continued propagation of cracks into the carbon and low alloy steels by a stress corrosion mechanism is unlikely.

Additionally, Reference 1 evaluates the effects of propagation of the flaws, left in place from the previous nozzles and welds, by fatigue crack growth and stress corrosion cracking mechanisms. Postulated flaws were assessed for flaw growth and flaw stability as specified in the ASME B & PV Code, Section XI and the results demonstrate compliance with the requirements of the ASME B & PV Code, Section XI.

Reference 2 stated that "The staff has found that WCAP 15973-P, Revision 01, is acceptable for referencing in licensing applications for Combustion Engineering designed pressurized water reactor to the extent specified and under the limitations delineated in the TR (Topical Report) and in the enclosed SE (Safety Evaluation)."

Sections 4.1, 4.2 and 4.3 of the SE present additional conditions to assess the applicability of the topical report. The FPL response for each additional condition is provided below. The FPL response is in *italic* font. The discussion shows that Reference 1 is applicable to St. Lucie Unit 2.

Section 4.1 of the SE states that Licensees seeking to use the methods of the TR will need to perform the following plant-specific calculation in order to confirm that the ferritic portions of the vessels or piping within the scope of the TR will be acceptable for service through the licensed lives of their plants (40 years if the normal licensing basis plant life is used or 60 years if the facility is expected to be approved for extension of the operating license):

1. Calculate the minimum acceptable wall thinning thickness for the ferritic vessel or piping that will adjoin to the MNSA repair or half nozzle repair.

   FPL Response: Based upon the content provided in Reference 4, the corrosion calculations herein, will address the Limiting Allowable Diameter, as described in

Reference 5, in lieu of the minimum acceptable wall thickness for the vessel or piping. The Limiting Allowable Diameters, as described in Reference 5, for the various nozzles under evaluation are shown in Tables 2A and 2B and the associated weld joint designs are shown in Figure 1 herein.

2. Calculate the overall general corrosion rate for the ferritic materials based on the calculation methods in the TR, the general corrosion rates listed in the TR for normal operations, startup conditions (including hot standby condition) and cold shutdown conditions and the respective plant-specific times in (in-percentages of total plant life) at each of the operating modes.

FPL Response: The overall general corrosion rate was determined using the calculation methods in the TR and St. Lucie Unit 2 generation data from 1/1/95 to 12/31/04. The percentage of total plant time spent at each of the temperature conditions follows:

High temperature conditions	*93.5%*
Intermediate temperature conditions	*1.5%*
Low temperature conditions	*5%*

The corrosion rate for each temperature condition is taken from the TR and is shown as follows:

High temperature conditions	*0.4 mpy*
Intermediate temperature conditions	*19 mpy*
Low temperature conditions	*8.0 mpy*

The overall corrosion rate was determined using the above time at temperature data, corrosion rate at temperature data and formula 1 of the TR as follows:

$$CR=0.935 \times 0.4mpy+0.015 \times 19\ mpy+0.05 \times 8mpy$$

Resulting in an overall corrosion rate of 1.06 mpy. This corrosion rate is applicable only to the "half nozzle" repair.

3. Track the time at cold shutdown conditions to determine whether this time does not exceed the assumptions made in the analysis. If these assumptions are exceeded, the licensees shall provide a revised analysis to the NRC and provide a discussion on whether volumetric inspection of the area is required.

FPL Response: In accordance with Section 2.3.4 of the SE, the corrosion rate for CE plants is based on a time split of 88 percent at operating conditions, 2 percent at intermediate temperature startup conditions and 10 percent at low temperature outage conditions. An assessment of operating data for St. Lucie Unit 2 from 1/1/95 through 12/31/04 shows a time split of 93.5 percent at operating *conditions, 1.5 percent at intermediate temperature startup conditions, and 5 percent of plant time at low temperature outage conditions. Therefore, the time at cold shutdown does not exceed the assumptions made in the analysis.*

The plant operating conditions will be reassessed for the resubmittal of this relief request at the start of the next inspection interval, which begins in August 2013. There is no need to track plant operating conditions during the remainder of the current inspection interval as there is sufficient wall thickness in the more limiting hot leg piping to maintain the limiting allowable diameter until this reassessment is made. As shown in WCAP-15973-P-A Rev. 1, the most severe corrosion rate for steady state conditions, i.e. at power or shutdown, would occur during outage or shutdown conditions with a corrosion rate of 8 mpy. Using the calculated corrosion rate of 1.06 mpy, from 2003 for two years, the wall would have experienced a radial loss of 0.002 in. to date. If the plant remained shut down for the remainder of the inspection interval, approximately 8 years, and experienced corrosion of the steel at the rate shown in the TR, approximately 8 mpy, there would be an additional loss of 0.064 in. of wall thickness. The total loss, 0.002 in. plus 0.064 in., would equal 0.066 in. Doubling the loss to account for a diametrical change and adding the diameter of 1.063 in., from Table 2A, results in a diameter of 1.195 in. at the start of the next inspection interval. A diameter of 1.195 in. is less than the limiting diameter of 1.270 in. identified in Reference 12 of WCAP-15739-P, Rev. 01. This calculation was performed for a "half nozzle" repair only. As shown below the corrosion rate for the "sleeve" repair has a lifetime diametrical loss of 0.025 in. and therefore is bounded by the calculation for the "half nozzle" repair.

4. Calculate the amount of general corrosion based thinning for the vessels or piping over the life of the plant, as based on the overall general corrosion rate calculated in Step 2 and the thickness of the ferritic vessel or piping that will adjoin to the MNSA repair or half nozzle repair.

FPL Response: The amount of corrosion will be determined for two cases; 1) the overall general corrosion rate which is applicable to the half nozzle repairs and 2) the corrosion rate for tight crevices which is applicable to the sleeve repairs.

As shown in TABLE 1, the first "half nozzle" repair to piping was made in 2003 and the first "sleeve" repair to piping was made in 1989; the first "half nozzle" repair to the pressurizer was made in 1994 and the first "sleeve" repair to the pressurizer was made in 1995.

The plant license was renewed and it expires on April 6, 2043. The first half nozzle repairs, made in 1994, can be expected to see 49 more years of service. Applying the corrosion rate from step 2, 1.06 mils per year, for 49 years, results in a radial material loss of 51.9 mils (diametrical loss of 104 mils) for the half nozzle repairs.

The first "sleeve" repairs were made in 1989 and can be expected to see 54 more years of service. As shown in WCAP-15973-P-A Revision 0, Reference 1, Section 2.5, a reasonable estimate of the lifetime corrosion resulting from a tight crevice will be a radial material loss of 12.5 mils (diametrical loss of 25 mils) which is considered applicable to the sleeve repairs.

5. Determine whether the vessel or piping is acceptable over the remaining life of the plant by comparing the worst case remaining wall thickness to the minimum acceptable wall thickness for the vessel or pipe.

   FPL Response: In TABLES 2A and 2B, the third column from the left lists the nozzle bore in the piping or pressurizer, resulting from replacement of the Alloy 600 nozzle. Also in TABLES 2A and 2B, the radial material loss, from Step 4 above, is doubled and added to the repair bore diameter. The resultant nozzle diameter is compared to the Limiting Allowable Diameter, from Step 1. For the nozzle locations shown, the resultant diameter is less than the Limiting Allowable Diameter.

   Therefore the hot leg piping and the pressurizer are acceptable for the remaining life of the plant.

Section 4.2 of the SE states that Licensees seeking to reference this TR for future licensing applications need to demonstrate that:

1. The geometry of the leaking penetration is bounded by the corresponding penetration reported in Calculation Report CN-CI-02-71, Revision 01.

   FPL Response: Plant specific calculations to evaluate fatigue crack growth associated with small diameter nozzles have been performed, Reference 6. The calculations and results are equivalent to Calculation Report CN-CI-02-71, Revision 01. The calculations of Reference 6 do not address the pressurizer heater sleeves. However, the geometry of the St. Lucie Unit 2 pressurizer heater sleeves is equivalent to that shown in Calculation Report CN-CI-02-71, Rev. 1. Therefore, the geometry of the nozzles on St. Lucie Unit 2 are bounded by Calculation Report CN-CI-02-71, Rev. 1. Reference 6 was submitted to the NRC as part of the St. Lucie License Renewal activity which resulted in an extended license for St. Lucie Unit 2.

2. The plant-specific pressure and temperature profiles in the pressurizer water space for the limiting curves (cooldown curves) do not exceed the analyzed profile shown in Figure 6-2 of Calculation Report CN-CI-02-71, Revision 01, as stated in Section 3.2.2 of this SE.

   FPL Response: The TR indicated that *the pressurizer cool down profile analyzed* *is a 200 degree F per hour cooldown rate from 653 degrees F to 200 degrees F followed by a 75 degree F per hour rate to 120 degrees F. The TR indicates that the fatigue evaluation results are not affected by the choice of cooldown rate from 653 degrees F to 200 degrees F and that the only concern is when the metal temperature is less than 200 degrees F when the material toughness begins to significantly decrease.*

Cooldown of the pressurizer water space is administratively controlled by a plant procedure to a maximum rate of 75 degrees F per hour for normal operation, which is within the rates shown in Figure 6-2 of CN-CI-02-71. Additionally, fluid temperature is recorded until a temperature of 120 degrees F is attained.

Therefore the temperature profile in the pressurizer water space does not exceed the analyzed profile shown in Figure 6-2 of CN-CI-02-71.

3. The plant-specific Charpy USE data shows a USE value of at least 70 ft-lb to bound the USE value used in the analysis. If the plant-specific Charpy USE data does not exist and the licensee plans to use Charpy USE data from other plants' pressurizers and hot leg piping, then justification (e.g., based on statistical or lower bound analysis) has to be provided.

   FPL Response: Charpy USE value of 70 ft-lb was used to support an EPFM analysis of the pressurizer lower shell and the pressurizer lower head. The analysis was not performed on the upper head because the upper head is not affected by the large in-surge transient or thermal stress which occurs at the lower head and lower shell. When the pressurizer was built, Charpy USE data for the pressurizer was not required and was not determined. RTNDT was determined for the pressurizer lower shell (two plates) and lower head, Table 5.2.9 of Reference 3, and impact properties (absorbed energy, lateral expansion, and fracture appearance) were determined.

   Charpy USE data was determined for six plates in the reactor vessel shell, Table 5.2.7 of Reference 3. The pressurizer lower shell and lower head and the six plates from the reactor vessel are very similar. All were made to the same specification, SA-533 Gr. B Cl.1, have similar chemistry and received similar heat treatment. The pressurizer lower head and the six plates from the reactor vessel were made by Lukens Steel. The pressurizer lower shell was supplied by Marrel Freres. Since the nine items are similar, it can be reasonably expected that the USE of the pressurizer lower shell and bottom head should be comparable to that of the reactor vessel plates, as discussed below. TABLE 3 summarizes impact data of the nine items. The impact data is taken from the material certification reports.

   The impact data for the reactor vessel plates was selected from the full impact curves developed for the plates and data was chosen at temperatures *comparable to that used for testing the pressurizer material.*

It can be seen that the pressurizer lower shell plate, Heat No. NR 60 466-2, exhibited an absorbed energy of 72 ft-lb and 35% shear at +20 degrees F. The USE value is the absorbed energy at 100% shear and this shear state is obtained by testing at progressively higher temperatures. As the testing temperature is increased, the absorbed energy increases and the percent shear increases. Since this material already exhibits the required 70 ft-lb at low temperatures, it will continue to exhibit and exceed the required value of 70 ft-lb while approaching full shear.

Similarly for the pressurizer bottom head, the absorbed energy at +70 degrees F is 69 ft-lb and the absorbed energy will increase as 100% shear is obtained. It can be reasonably expected that this material will exhibit an USE of at least 70 ft-lb.

The pressurizer lower shell plate, Heat No. NR 61 734-1, exhibited absorbed energy comparable to that of the six reactor vessel plates. The impact values at + 30 degrees F are quite similar for both absorbed energy and percent shear. Since all seven plates have similar chemistry and experienced similar heat treatment and exhibit similar low temperature properties, it is reasonable to expect the USE of the pressurizer lower shell plate, Heat No. NR 61 734-1, to be comparable to that of the six reactor vessel plates which exhibit USE well in excess of 70 ft-lb.

Therefore it is reasonable to expect that the plate in the lower shell and head of the pressurizer would exhibit USE well in excess of 70 ft-lb and that St. Lucie Unit 2 is bounded by the analysis.

The concluding requirement of section 4.2 states "Based on the above evaluation, the staff has determined that the crack can be left in the J-groove weld at small-bore locations for a plant life of 40 years. However, if the licensee plans on using this alternative beyond the 40 years and through the license renewal period, the thermal fatigue crack growth analysis shall be re-evaluated to include the extended period, as applicable, and submitted as a time limited aging analysis in their license renewal application as required by 10 CFR 54.21(c)(1)."

FPL Response: As stated above, *in response to 4.1.4 of the SE, the first small bore alloy 600 nozzle repair can be expected to see 54 more years of service, which extends beyond the original plant life of 40 years and into the license renewal period. The St. Lucie plant has received an extended license for both Units 1 and 2. The FSAR for Unit 2, Reference 3, in Chapter 18, describes the aging management programs and time limited aging analysis activities for license renewal. Chapter 18, section 18.3.7 specifically addresses alloy 600 instrument nozzle repairs. This section concludes "The flaw growth analysis of the Unit 2 pressurizer steam space* *alloy 600 instrument nozzle repairs has been evaluated and determined to remain valid for the period of extended operation."*

Section 4.3 of the SE states that Licensees seeking to implement MNSA repairs or half nozzle replacements may use the WOG's stress corrosion assessment as the bases for concluding that existing flaws in the weld metal will not grow by stress corrosion if they meet the following conditions:

1. Conduct appropriate plant chemistry reviews and demonstrate that a sufficient level of hydrogen overpressure has been implemented for the RCS and that the contaminant concentrations in the reactor coolant have been typically maintained at levels below 10 ppb for dissolved oxygen, 150 ppb for halide ions and 150 ppb for sulfate ions.

   FPL Response: Hydrogen overpressure is implemented in the RCS by typically maintaining volume control tank hydrogen overpressure between 25 and 35 psig. RCS contaminant concentrations for dissolved oxygen, halide ions and sulfate are maintained at less than 5 ppb. All of these values are steady state values.

   The reactor coolant system water is analyzed for dissolved oxygen and halides three times per week with no interval between analysis to exceed 72 hours. Analysis for dissolved oxygen is not required when the reactor coolant system Tavg is less than or equal to 250 degrees F. Analysis for halides is not required when all fuel is removed from the reactor vessel and the reactor coolant system Tavg is less than 140 degrees F. The reactor coolant system water is analyzed for sulfate ions at least once per 7 days.

2. During the outage in which the half nozzle or MNSA repairs are scheduled to be implemented, licensees adopting the TR's stress corrosion crack growth arguments will need to review their plant specific RCS coolant chemistry histories over the last two operating cycles for their plants and confirm that these conditions have been met over the last two operating cycles.

   FPL Response: The contaminant limits, as stated in response to paragraph 1, immediately above, have been maintained at steady state operation during the past two cycles. The analysis results for the last two cycles were reviewed and no transients were identified.

This Relief Request applies to all previous repairs to alloy 600 small bore nozzles on the hot leg reactor coolant piping and pressurizer that have left a remnant nozzle in place and all similar future repairs including pressurizer heater sleeve repairs that will leave a remnant heater sleeve in place.

In conclusion, the ASME B & PV Code Section XI requirement, IWB-3132.2, is to correct a component containing a flaw. The proposed alternative is to relocate the pressure boundary weld and not correct the component containing the flaw but show by analysis that the material and the presence of the flaw will not be detrimental to the pressure retaining function of the reactor coolant piping and pressurizer. Analyses, reference 1, have shown that allowing the material containing a flaw to remain in place and in service would not result in a reduction of the level of quality or safety.

6. Duration of Proposed Alternative

Relief is requested for the remainder of the current inspection interval for St. Lucie Unit 2 which expires in August 2013.

7. References

1) WCAP-15973-P-A, Rev 0 (NRC approved version of WCAP-15973-P, Revision 1 with SER and resolved questions) "Low-Alloy Steel Component Corrosion Analysis Supporting Small-Diameter Alloy 600/690 Nozzle Repair/Replacement Programs", Westinghouse Electric Company LLC, February 2005

2) NRC letter dated January 12, 2005, Subject: Final Safety Evaluation for Topical Report WCAP-15973-P, Rev 01 "Low-Alloy Steel Component Corrosion Analysis Supporting Small-Diameter Alloy 600/690 Nozzle Repair/Replacement Program" (TAC No. MB6805)

3) St. Lucie Unit 2 Updated Final Safety Analysis Report through Amendment No. 16

4) NRC letter to Mr. J. A. Stall dated August 11, 2005 "St. Lucie Nuclear Plant, Unit 1 - Request for Additional Information Regarding Relief Request No. 26 - Repair of Alloy 600 Small Bore Nozzles Without Flaw Removal" (TAC No. MC6944)

5) A-CEOG-9449-1242 Rev. 00 (Task 1131) "Evaluation of the Corrosion Allowance for Reinforcement and Effective Weld to Support Small Alloy 600 Nozzle Repairs"

6) Westinghouse Calculation Note Number CN-CI-02-69, Rev. 0 "Evaluation of Fatigue Crack Growth Associated with Small Diameter Nozzles for St. Lucie 1 & 2"

TABLES

TABLE 1
Saint Lucie Unit 2 Alloy 600 Small Bore Nozzles Repair Status

Location	Tag ID	Repair Date	Repair Method (Figure 1 Design)	Reason for Repair	Flaw Left
PZR Stm Space Upper Head	A	1994	1/2 Nozzle Repair* (B)	Linear Indications	Yes
PZR Stm Space Upper Head	B	1994	1/2 Nozzle Repair* (B)	Linear Indications	Yes
PZR Stm Space Upper Head	C	1994	1/2 Nozzle Repair* (B)	Leakage / Linear Indications	Yes
PZR Stm Space Upper Head	D	1994	1/2 Nozzle Repair* (B)	Preventative	No
PZR Wtr Space Lower Head	RC-105	1995	Sleeve Repair* (C)	Preventative	No
PZR Wtr Space Lower Head	RC-130	1995	Sleeve Repair* (C)	Preventative	No
PZR Wtr Space Side Shell	TE-1101	1995	Sleeve Repair* (C)	Preventative	No
RCS Hot Leg RTD Nozzle	TE-1112HA	1989	Sleeve Repair* (C)	Preventative	No
RCS Hot Leg RTD Nozzle	TE-1111X	1989	Sleeve Repair* (C)	Preventative	No
RCS Hot Leg RTD Nozzle	TE-1122HC	1989	Sleeve Repair* (C)	Preventative	No
RCS Hot Leg RTD Nozzle	TE-1122HD	1989	Sleeve Repair* (C)	Preventative	No
RCS Hot Leg RTD Nozzle	TE-1121X	1989	Sleeve Repair* (C)	Preventative	No
RCS Hot Leg RTD Nozzle	TE-1112HB	2003	1/2 Nozzle Repair (A)	Preventative	No
RCS Hot Leg RTD Nozzle	TE-1112HC	2003	1/2 Nozzle Repair (A)	Preventative	No
RCS Hot Leg RTD Nozzle	TE-1112HD	2003	1/2 Nozzle Repair (A)	Preventative	No
RCS Hot Leg RTD Nozzle	TE-1122HA	2003	1/2 Nozzle Repair (A)	Preventative	No
RCS Hot Leg RTD Nozzle	TE-1122HB	2003	1/2 Nozzle Repair (A)	Preventative	No
RCS Hot Leg Flow Nozzle	PDT-1121B	1995	Sleeve Repair (D)	Leakage	Yes
RCS Hot Leg Flow Nozzle	PDT-1111A	1995	Sleeve Repair (D)	Preventative	No
RCS Hot Leg Flow Nozzle	PDT-1111B	1995	Sleeve Repair (D)	Preventative	No

TABLE 1 Saint Lucie Unit 2 Alloy 600 Small Bore Nozzles Repair Status					
Location	Tag ID	Repair Date	Repair Method (Figure 1 Design)	Reason for Repair	Flaw Left
RCS Hot Leg Flow Nozzle	PDT-1111C	1995	Sleeve Repair (D)	Preventative	No
RCS Hot Leg Flow Nozzle	PDT-1111D	1995	Sleeve Repair (D)	Preventative	No
RCS Hot Leg Flow Nozzle	PDT-1121A	1995	Sleeve Repair (D)	Preventative	No
RCS Hot Leg Flow Nozzle	PDT-1121C	1995	Sleeve Repair (D)	Preventative	No
RCS Hot Leg Flow Nozzle	PDT-1121D	1995	Sleeve Repair (D)	Preventative	No
RCS Hot Leg Flow Nozzle	Sample Line	1995	Sleeve Repair (D)	Preventative	No

*Nozzle welded to a nickel alloy weld pad

TABLE 2A SUMMARY OF LIMITING ALLOWABLE DIAMETER CALCULATIONS FOR HALF NOZZLE REPAIRS					
Nozzle Location	Weld Joint Design (Figure 1)	Nozzle Repair Bore Diameter (inch)	Diameter Corrosion Loss After 49 Years (inch)	Repair Bore Diameter After 49 Years (inch)	Limiting Allowable Diameter (inch)
Hot Leg Piping	A	1.063	0.0519	1.167	1.27
Pressurizer Upper Head	B	1.325	0.0519	1.429	2.26
Pressurizer Heater Sleeve	B	1.662	0.0519	1.766	2.26

TABLE 2B SUMMARY OF LIMITING ALLOWABLE DIAMETER CALCULATIONS FOR SLEEVE REPAIRS					
Nozzle Location	Weld Joint Design (Figure 1)	Nozzle Repair Bore Diameter (inch)	Diameter Corrosion Loss After 54 Years (inch)	Repair Bore Diameter After 54 Years (inch)	Limiting Allowable Diameter (inch)
Hot Leg Piping	C D	1.129 1.178	0.025 "	1.154 1.203	1.27 1.27
Pressurizer Side Shell Lower Head	 C C	 1.5 1.325 and 1.5	 0.025 " "	 1.525 1.35 1.525	 1.62 2.26 2.26

TABLE 3 SUMMARY OF CHARPY IMPACT DATA					
Name	Heat No.	Testing temperature °F	*Absorbed energy ft-lb	*% shear	*USE ft-lb
Reactor Vessel Plate	A8490-2	+30	44	25	105
Reactor Vessel Plate	B3416-2	+10	42	20	113
Reactor Vessel Plate	A8490-1	0	49	25	115
Reactor Vessel Plate	B8307-2	+20	33	15	93
Reactor Vessel Plate	A3131-1	+20	47	20	107
Reactor Vessel Plate	A3131-2	+20	52	25	105
Pressurizer Bottom Head	C4754-3	+70	69	60	——
Pressurizer Lower Shell	NR 60 466-2	+20	72	35	——
Pressurizer Lower Shell	NR 61 734-1	+30	54	25	——

*Average of three tests

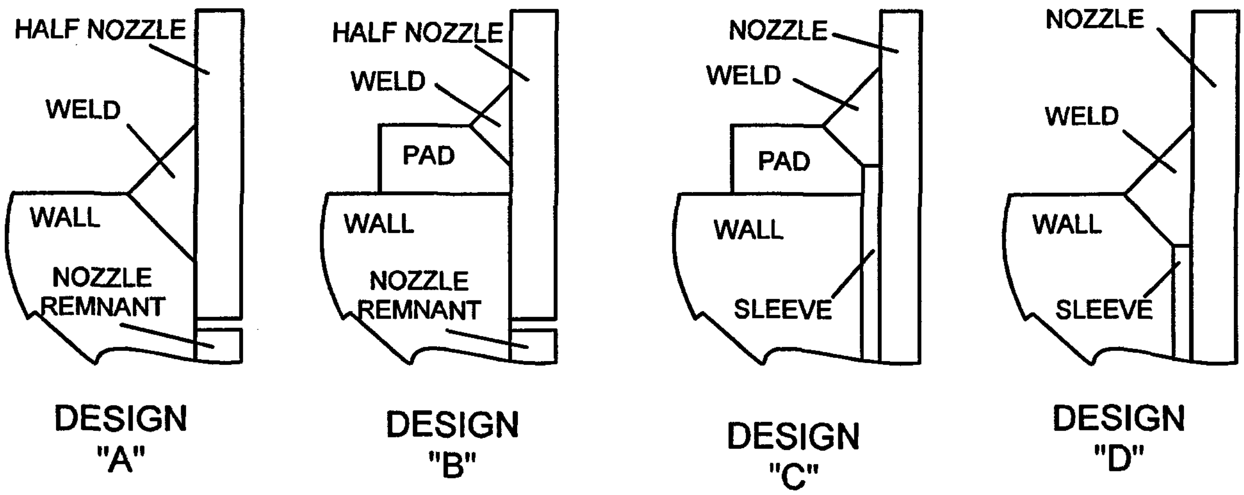

FIGURE 1
REPLACEMENT NOZZLE CONFIGURATIONS