Florida Power & Light Company, 6351 S. Ocean Drive, Jensen Beach, FL 34957

FPL

July 19, 2000

L-2000-141
10 CFR 50.90

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

RE: St. Lucie Units 1 and 2
Docket Nos. 50-335 and 50-389
FPL RAI Response For
PSV/MSSV PLA

Reference: NRC letter dated May 4, 2000, "St. Lucie Plant, Units 1 and 2 – Request for Additional Information Regarding the Main Steam and Pressurizer Code Safety Valve Setpoint Setting (TAC NOS. MA8109 and MA8110)."

By FPL letter L-2000-001, dated January 19, 2000, Florida Power and Light Company (FPL) requested to amend Facility Operating Licenses DPR-67 for St. Lucie Unit 1 and NPF-16 for St. Lucie Unit 2 by revising the Unit 1 and 2 Technical Specifications to be consistent with the Standard Technical Specifications (STS) requirements that allow for an expanded as-found testing acceptance tolerance (i.e., beyond ±1%) for the main steam safety valves (MSSVs) and pressurizer code safety valves (PSVs). By the above reference, the NRC forwarded a request for additional information (RAI) regarding the submittal. Attached is FPL's response to the RAI.

Attachment 1 contains the FPL response. Attachments 2 and 3 contain copies of the affected Technical Specifications pages marked up to show the proposed changes. The RAI response remains bounded by the original No Significant Hazards Determination. As discussed with the NRC St. Lucie Project Manager, K. N. Jabbour, this submittal exceeded the 60 day target date in order to be reviewed by the FPL Company Nuclear Review Board.

The proposed amendments have been reviewed by the St. Lucie Facility Review Group and the FPL Company Nuclear Review Board. In accordance with 10 CFR 50.91 (b) (1), a copy of the RAI response is being forwarded to the State Designee for the State of Florida.

A001

Please contact us if there are any questions about this submittal.

Very truly yours,

Rajiv S. Kundalkar

Rajiv S. Kundalkar
Vice President
St. Lucie Plant

RSK/EJW/KWF

Attachments

cc: Regional Administrator, Region II, USNRC
Senior Resident Inspector, USNRC, St. Lucie Plant
Mr. W. A. Passetti, Florida Department of Health and Rehabilitative Services

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

Rajiv S. Kundalkar being first duly sworn, deposes and says:

That he is Vice President, St. Lucie Plant, for the Nuclear Division of Florida Power and Light Company, the Licensee herein;

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

Rajiv S. Kundalkar

Rajiv S. Kundalkar

STATE OF FLORIDA

COUNTY OF ST LUCIE

Sworn to and subscribed before me

this 19 day of JULY, 20 00

by Rajiv S. Kundalkar, who is personally known to me.

George R Madden

Signature of Notary Public-State of Florida

GEORGE R. MADDEN
Notary Public - State of Florida
My Commission Expires Jun 17, 2004
Commission # CC931387

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

FPL RAI Response
For
PSV/MSSV PLA

St. Lucie Units 1 and 2
Docket Numbers 50-335 and 50-389
FPL RAI Response for PSV/MSSV PLA
TAC Numbers MA8109 and MA8110

Background

In reference 8, the NRC forwarded a request for additional information (RAI) concerning the proposed license amendment (PLA) for the as-left vs. as-found pressurizer safety valve (PSV) and main steam safety valve (MSSV) lift setpoints submitted by FPL letter L-2000-001, dated January 19, 2000. This attachment contains the FPL response to the RAI. The Technical Specification (TS) change mark ups are included in Attachments 2 (Unit 1) and 3 (Unit 2). The TS marked up changes are administrative in nature. Therefore the conclusions of the original determination of No Significant Hazards Evaluation and Environmental Consideration Statement are not affected by this response.

FPL Responses

Question 1

The licensee's submittal dated January 19, 2000, states that the proposed technical specification (TS) changes are consistent with the approved Standard Technical Specifications (STS). However, the proposed changes to Limiting Condition for Operation (LCO) 3.4.3, LCO 3.7.1.1, and Table 4.7-1 for Unit 1, and to LCO 2.4.2.2, LCO 3.7.1.1, and Table 3.7-2 for Unit 2, are not consistent with the STS. The proposal would remove the valve lift settings required for the valves to be OPERABLE during Modes 1, 2, and 3 (as demonstrated by the as-found settings during surveillance) and replaces them with the as-left settings. The STS places the as-left +/-1% resetting tolerance in the Surveillance Requirements for the valves, not in the LCO, and places the as-found tolerance in the LCO as a limit of acceptable setpoint drift during plant operation The purpose of the LCO is to indicate how much the settings can change during operation and remain OPERABLE, not the as-left setting prior to operation. Therefore, please address whether your proposed TS change should be revised to be consistent with the STS.

FPL Response:

FPL agrees that the LCO should contain the as-found setpoint tolerances, and that the as-left resetting tolerance belongs in the surveillance requirements for the valves. The revised TS changes are contained in Attachments 2 and 3.

Question 2

Uncertainties of analysis parameters should be accounted for in the safety analyses used to justify new limits in the plant TS. Provide a discussion of the pressurizer safety valve (PSV) and main steam safety

valve (MSSV) setpoint testing instrument accuracy and how this source of uncertainty is accounted for in the licensee's safety analysis associated with the proposed TS PSV and MSSV setpoint tolerances.

FPL Response:

Main Steam Safety Valve Accuracy

FPL sets and tests the main steam safety valves with equipment that measures the hydraulically assisted stem load required to overcome the closing spring force and initiate valve opening. The stated intent of Paragraph 1.4.1.2 of the ASME OM Code (Reference 5) is that test equipment used in conjunction with the determination of valve set pressure have an overall combined accuracy within +2% to -1% at the pressure level of interest. The effect of the specified overall combined accuracy is that the limits of the actual set pressure may be 1% above to 2% below the indicated (measured) set pressure.

In a traditional lift test, the test accuracy is solely dependent on the combined accuracy of the steam pressure instrumentation. In both the previously used air set assisted lift test and the hydraulically assisted lift test, the measurement of the air/hydraulic pressure (i.e., lift assist force on the valve stem) must be converted to an equivalent steam pressure. Any difference in the nominal mean seat area and the actual effective seat area of the valve introduces the potential for additional test error. Since the error introduced by the assumed seat area cannot be directly measured and quantified, confidence of the methodology accuracy is obtained through comparison of assisted lift test results with a traditional lift test and the valve's dimensional fabrication tolerances.

A set point correlation test for the test equipment was performed with a spare St. Lucie MSSV. Eight traditional lifts were performed (average lift: 1028.5 psig), followed by five hydraulically assisted tests at 80% steam pressure (average lift: 1023.4 psig) with a final confirmatory traditional lift test (1033 psig). The first four traditional lift tests showed signs of pre-lift at 1025 psig with actual lift occurring at 1030-1037 psig. As the first four traditional lift tests showed signs of pre-lift, the correlation test began with Test #5 when clean lifts began. The valve seat area used for the correlation test was 22.438 square inches which was based on the average of the nozzle seat ID and OD as provided by Crosby to VR-TESCO.

Lift Pressure (Traditional Lifts #5-#8)	1018-1025 psig	(1021 psig average)
Lift Pressure (Hydraulic Assisted Lifts #9-#13)	1016-1027.6 psig	(1023.4 psig average)

The differences between the test averages is 2.4 psi or .24%, well within the 1.0% accuracy claim for the Sharp Eye System and meeting the intent of Paragraph 1.4.1.2 of the ASME OM Code. Note that each of the individual hydraulically assisted tests are also within .65% of the mean of the traditional lifts; this individual test performance also meets the 1.0% accuracy claim with sufficient margin for the pressure gauge's inaccuracy.

Additionally, Wyle Labs sets and tests the MSSVs after refurbishment. The equipment used consists of a pressure transducer, strain gage amplifier, and an A/D converter. The accuracy of this test equipment was determined to be +/- 0.10% of full scale or 1.510 psi.

Pressurizer Safety Valve Accuracy

The pressurizer safety valves are set and tested by Wyle labs. The equipment used consists of a pressure transducer, strain gage amplifier, and an A/D converter. The accuracy of this test equipment was determined to be +/- 0.10% of full scale or 3.020 psi.

Accident Analyses Conservatisms

Although the safety analyses do not include any uncertainties associated with relief valve lift setting accuracies, the relevant accident analyses have conservatism associated with the methodology and key parameters of interest when compared to realistic expected plant conditions. These conservatisms include:

- The lowering of the initial secondary side pressure below the normal operating pressure (after accounting for expected variations) so as to delay the opening of the MSSVs,
- The lowering of the initial primary side pressure below the normal operating pressure (after accounting for expected variations) so as to delay the opening of the PSVs, and
- The actuation of reactor trips and engineered safeguards with uncertainties applied deterministically.

Instrument uncertainties associated with the surveillance testing are not specifically accounted for in the analyses, nor in the testing itself. However, the uncertainties and associated setpoint drifts are expected to be random both above and below the nominal setpoint. In the analysis, all of the valves are conservatively assumed to be at the maximum tolerance allowed. In fact a less conservative, but more realistic approach would be an average of the values (i.e., the nominal setpoint). Because of these and other conservative assumptions discussed above, use of the TS tolerance values without accounting for testing uncertainties is justified.

Question 3

As documented in NRC Integrated Inspection Report 50-335/98-12 and 50-389/98-12, the licensee's Generic Letter 96-05 program establishes a goal of 10% margin to account for age-related degradation of motor-operated valve (MOV) performance. However, changes to the differential pressure loads on valves, which result from the proposed TS amendment, are not age-related degradation, but are changes to the design basis for the valves. The inspection report also found that, at that time, the licensee was maintaining an up-to-date design basis for GL 96-05 valves. Provide verification that the functional capability of all safety-related power-operated (motor-operated, air-operated, and hydraulically-operated) valves has been evaluated for the larger differential pressure loads resulting from the increased TS PSV and MSSV setpoint tolerances.

FPL Response:

These license amendments do not change the as-found upper lift setpoint tolerance for the MSSV. Because the upper limit for the MSSV lift setpoint remains at +1%, there is no change to design margins associated with the secondary and associated systems power operated valves that may act against pressures equivalent to the MSSV lift setpoint. The increased tolerance for the upper limit PSV setpoint may affect design margins for primary system power operated valves that may act against the higher PSV lift pressures. Lower MSSV and PSV setpoint tolerances have no affect on existing design margins. Additionally, there are no hydraulic valves that would be affected by larger differential pressure loads resulting from the increased PSV setpoint tolerances.

MOVs

A review of the motor operated valves (MOVs) within the St. Lucie Generic Letter 89-10 program shows that only the Unit 1 and 2 PORV block valves utilize the primary safety valve nominal pressure setpoint in determining the open stroke design basis differential pressure (DP). The closing stroke design basis DP uses a lower value which is based on the PORV setpoint and not related to safety valve lift pressure. The affect of revising the as-found setpoint tolerance of the PSV's up to +3% for the Unit 1 and 2 PORV block valves is evaluated below.

The Unit 1 PORV block valves (V1403 and V1405) have a design basis opening stroke DP of 2485 psid which is based on the nominal PSV setpoint. The logic being that any attempt to open the PORV block valve would occur prior to reaching the setpoint of the safety valve since the reactor trips at a setpoint of 2385 psig and the valve begins to relieve pressure at 2485 psig. Since the design requirement of the PORV block valves is to open before the safety valves lift, use of the nominal PSV setpoint in establishing the thrust requirements is acceptable. Opening the PORV block valve at the PSV setpoint is not expected.

A review of the actuator capability calculation shows that there is greater than 13% design margin available for the opening stroke of the Unit 1 PORV block valves in addition to the numerous program conservatisms and 22.5% margin for rate of loading. Therefore, sufficient margin is available to account for any age-related degradation (10%) plus the potential increase in required opening thrust due to the +3% PSV setpoint tolerance.

The Unit 2 PORV block valves (V1476 and V1477) have a design basis opening stroke DP of 2485 psid which is based on the nominal PSV setpoint. The logic being that any attempt to open the PORV block valve would occur prior to reaching the setpoint of the safety valve since the reactor trips at a setpoint of 2370 psia and the valve begins to relieve pressure at 2485 psig. Since the design requirement of the PORV block valves is to open before the safety valves lift, use of the nominal PSV setpoint in establishing the thrust requirements is acceptable. Opening the PORV block valve at the PSV setpoint is not expected.

A review of the actuator capability calculation shows that there is greater than 15% design margin available for the opening stroke of the Unit 2 PORV block valves in addition to the numerous program conservatisms and 22.5% margin for rate of loading. Therefore, sufficient margin is available to

account for any age-related degradation (10%) plus the potential increase in required opening thrust due to the +2% PSV setpoint tolerance.

As mentioned above, the St. Lucie Generic Letter 89-10 Program also contains numerous conservatisms in addition to the design margin that is directly visible for the Unit 1 and 2 PORV block valves. These conservatisms include:

- Actuator efficiencies
- Undervoltage assumptions
- Stem factor coefficient of friction (COF)
- Valve factors
- Testing equipment inaccuracies
- Rate of loading assumptions
- Packing load assumptions

The above evaluation has discussed the use of the nominal PSV setpoint for the Unit 1 and 2 PORV block valves opening stroke based on its design basis function. Since the function of the block valve is to open to prevent lifting of the PSV, use of the nominal PSV setpoint in establishing the thrust requirements is acceptable. In addition, the Unit 1 and 2 PORV block valves contain sufficient design margin to account for any age-related degradation (10%) plus the potential increase in required opening thrust due to the +3% (Unit 1) and +2% (Unit 2) PSV setpoint tolerance in addition to the numerous MOV program conservatisms and 22.5% margin for rate of loading. Therefore, no further evaluation is required.

AOVs

With regards to air operated valves (AOVs) that may be affected by the proposed change, FPL performed an assessment for AOVs that communicate directly with the reactor coolant system (RCS) and thus, have the potential to be impacted by the increased PSV setpoint tolerances. RCS sample line and chemical volume and control system let down line isolation valves (V2515, V2516, V5200, V5201, V5202 for Unit 1 and V2515, V2522, V5203, V5204, V5205 for Unit 2) were determined to be potentially affected by this change. These valves function as containment isolation valves that receive close signals on a containment isolation signal (CIS). CIS is indicative of a RCS depressurization transient. Therefore, these valves would not need to automatically close against RCS pressures approaching the PSV lift setpoint. The increased PSV setpoint tolerance has no impact on the safety related automatic containment isolation function. Furthermore, the nominal operating DP is 2485 psia. FPL reviewed Flowscan data on V2515 of Unit 1 and 2 that showed that the seating load remained positive when the operating pressure was increased from 2485 to 2560 psig. Therefore, the valves would still close with RCS pressures at +3% of the nominal PSV lift setpoint.

Question 4

Provide the results of your reanalyses for the transients and accidents (including but not limiting to the loss of external load and small break LOCA) that are affected by the proposed changes of PSV and MSSV set point tolerances for Units 1 and 2. The information provided should include the following:

a. Major assumptions used in these analyses (especially, those that are different from the analyses of record and affected by the proposed TS changes).
b. the peak clad temperature following a small break LOCA and the peak RCS pressure following the limiting case for each event category from your reanalyses and the comparative values from the analyses of record, and
c. the amount of dose release following a steam generator tube rupture from the reanalyses and its comparison with your analyses of record.

FPL Response:

There were no reanalyses performed to support the proposed TS changes. The proposed TS changes related to the tolerances of pressurizer safety valves (PSVs) and the main steam safety valves (MSSVs) are supported by all the pertinent current analyses of record for St. Lucie Units 1 and 2. A summary is provided below:

St. Lucie Unit 1

The design basis events whose consequences are sensitive to the safety valves setpoints are the pressurization events and the small break LOCA (SBLOCA). The limiting pressurization event is the loss of external load (LOEL). Control element assembly (CEA) withdrawal event analyzed in Reference 9 is bounded by LOEL from pressurization viewpoint and is not sensitive to the safety valve setpoints from thermal margin considerations. The asymmetric steam generator transient is bounded by the symmetric events with respect to the pressurization criteria and is analyzed in Reference 9 from departure from nucleate boiling ratio (DNBR) and centerline melt consideration which is unaffected by the safety valve setpoints. The feedwater line break event is a cooldown event in the St. Lucie Unit 1 design basis and is not dependent on the MSSV setpoint.

i) The steam generator tube rupture analysis could potentially be impacted by the MSSV setpoint. In the St. Lucie Unit 1 analysis of record (described in Reference 9), however, the atmospheric dump valves are conservatively assumed to be manually opened just after the reactor trip, so that the MSSVs do not get actuated. This assumption results in increased steam releases to the atmosphere and conservative radiological doses. The steam pressure in this analysis remained below the MSSV setpoint -3% tolerance. The 0-2 hour doses as given in Reference 9 are:

Thyroid:	0.41 rem
Whole Body:	0.103 rem

ii) The analysis of record for LOEL is documented in Reference 10. This analysis was previously submitted to the NRC as part of the reactor coolant system (RCS) flow reduction license amendment (30% tube plugging) approved by the NRC in the license amendment # 145. There are no changes to the assumptions due to the proposed TS changes. The actual setpoint tolerance values supported by the analysis are:

MSSVs	# +1%	(analysis used +1%)
PSVs	# +3%	(analysis used +3%)

The peak reactor coolant system pressure in this analysis of record is 2714 psia. Biasing this analysis for 0% tube plugging to maximize primary-to-secondary heat transfer, as presented in the UFSAR (Reference 9), resulted in the peak secondary pressure of less than 1100 psia.

iii) The analysis of record for SBLOCA was performed by Siemens Power Corporation in 1999 and the resulting peak cladding temperature (PCT) was reported to the NRC in a 30-day 10 CFR 50.46 report (Reference 11). There are no changes to this analysis due to the proposed TS changes. The actual setpoint tolerance values supported by the analysis are:

MSSVs	# +3%	(analysis used +3%)
PSVs	Not used for depressurizing event.	

The peak cladding temperature as reported in Reference 12 is 1767 ^{0}F.

Summary:

The St. Lucie Unit 1 current analyses of record support the following MSSV and PSV setpoint tolerances:

MSSVs:	+1%	-3%
PSVs:	+3%	-2.5%

The negative tolerance on PSVs is specified as –2.5% so as to avoid opening of the PSVs prior to the reactor trip on high pressurizer pressure (after accounting for the pressure uncertainties) for the pressurization events. As discussed in the response to Question 2, the analyses have conservatism associated with the methodology and the key parameters when compared to realistic expected plant conditions.

St. Lucie Unit 2

The analyses whose consequences are sensitive to the safety valves setpoints are the pressurization events [loss of condenser vacuum (LOCV), feedline break (FLB), CEA withdrawal (CEAW), asymmetric steam generator transient (ASGT)], the steam generator tube rupture (SGTR), and the small break LOCA (SBLOCA).

i) The analysis of record for LOCV is documented in SL2-FE-0198, Rev. 4, submitted to the NRC in Reference 13 as part of the reload process improvement license amendment. The peak RCS pressure in this analysis remained below the limit of 2750 psia and the peak secondary pressure remained below the limit of 1100 psia. The Reference 13 submittal is approved by the NRC in the license amendment # 105. There are no changes to the assumptions due to the proposed TS changes. The actual setpoint tolerance values supported by the analysis are:

MSSVs	# +1%	(analysis used +1%)
PSVs	# +2%	(analysis used +2%)

ii) The analysis of record for FLB is documented in SL2-FE-0198, Rev. 4, submitted to the NRC in Reference 13 as part of the reload process improvement license amendment. This submittal is approved by the NRC in the license amendment # 105. There are no changes to the assumptions due to the proposed TS changes. The actual setpoint tolerance values supported by the analysis are:

MSSVs	# +3%
PSVs	# +3%

The dose consequences for this event as provided in Reference 14 are:

	EAB/2hr	LPZ/8hr
Thyroid	1.56 rem	0.71 rem
Whole Body	< 2 mrem	< 3 mrem

iii) The analysis of record for CEAW is documented in SL2-FE-0198, Rev. 4, submitted to the NRC in Reference 13 as part of the reload process improvement license amendment. This submittal is approved by the NRC in the license amendment # 105. There are no changes to the assumptions due to the proposed TS changes. The actual setpoint tolerance values supported by the analysis are:

MSSVs	# +1%	(analysis used +1%)
PSVs	# +3%	(analysis used +3%)

iv) The analysis of record for ASGT is documented in SL2-FE-0198, Rev. 4, submitted to the NRC in Reference 13 as part of the reload process improvement license amendment. This submittal is

approved by the NRC in the license amendment # 105. There are no changes to the assumptions due to the proposed TS changes. The actual setpoint tolerance values supported by the analysis are:

MSSVs	# +3%	(analysis used +3%)
PSVs	Not a sensitive parameter	

v) The analysis of record for SGTR is documented in SL2-FE-0198, Rev. 4, submitted to the NRC in References 13 as part of the reload process improvement license amendment. This submittal is approved by the NRC in the license amendment # 105. There are no changes to the assumptions due to the proposed TS changes. The actual setpoint tolerance values supported by the analysis are:

MSSVs	∃ -3%	(analysis used -3%)
PSVs	Not Used	

The dose consequences for this event as provided in Reference 14 are:

	EAB/2hr	LPZ/8hr
Thyroid PIS	12.0 rem	6.0 rem
Thyroid GIS	2.0 rem	8.0 rem
Whole Body	0.2 rem	0.1 rem

vi) The analysis of record for SBLOCA is documented in SL2-FE-0198, Rev. 4, submitted to the NRC in Reference 13 as part of the reload process improvement license amendment. This submittal is approved by the NRC in the license amendment # 105. There are no changes to the assumptions due to the proposed TS changes. The actual setpoint tolerance values supported by the analysis are:

MSSVs	# +1%	(analysis used +1%)
PSVs	Not used for depressurization event.	

The peak cladding temperature calculated in this analysis is 2055^{0}F.

Summary:

The St. Lucie Unit 2 current analyses of record support the following MSSV and PSV setpoint tolerances:

MSSVs:	+1%	-3%
PSVs:	+2%	-2%

The negative tolerance on PSVs is specified as –2% so as to avoid opening of the PSVs prior to the reactor trip on high pressurizer pressure (after accounting for the pressure uncertainties) for the

pressurization events. As discussed in the response to Question 2, the analyses have conservatism associated with the methodology and the key parameters when compared to realistic expected plant conditions.

Question 5

Discuss the methodology used for reanalyses of each event and confirm the consistency between the methodologies used in the reanalyses and the original licensing analyses. Identify any differences in methodology and provide justification.

FPL Response:

Since the proposed changes are based on and supported by the current analyses of record, there were no reanalyses performed as part of the proposed changes. The methodologies used in the current licensing analyses, therefore, remain applicable for the proposed changes to the safety valves setpoints. These methodologies are listed below:

St. Lucie Unit 1

The loss of external load (LOEL) analysis used the methodology described in Reference 15, whereas the small break LOCA analysis used the methodology from Reference 16. The steam generator tube rupture analysis described in Reference 9 is based on the methodology approved in license amendment # 48.

St. Lucie Unit 2

The methodology used in the current analyses of loss of condenser vacuum, feedwater line break, asymmetric steam generator transient, and steam generator tube rupture is in References 13 and 17. The CEA withdrawal analysis used the methodology described in References 13 and 18, whereas the small break LOCA analysis is based on the methodology in References 19, 20, and 21. All these analysis methodologies were part of the license amendment # 105.

Question 6

TS 3.7.1.1 requires returning the plant to hot shutdown within 12 hours. Please provide the basis for the 12 hours.

FPL Response:

FPL withdraws this change. This change is reflected in the marked up TS changes contained in Attachments 2 and 3.

Question 7

Pages 4 and 9 of Attachment 1 to the licensee's letter of January 19, 2000, discuss the TS changes related to PSV LCO reformatting for Units 1 and 2. At the end of page 9, it states that "The proposed changes to Unit 2 TS are similar to those described above for Unit 1 and are provided in Attachment 4. The only significant difference between the units is the temperature for which LTOP is required - 230°F for Unit 2...." However, the applicability of TS 3.4.3 for Unit 1 (page 4 of Attachment 3) was changed from "MODES 1, 2 and 3." to "MODES 1, 2, 3 and 4 with all RCS cold leg temperatures >281°F." The corresponding Unit 2 applicability (TS 3.4.2.2 (page 4 of Attachment 4)) remains unchanged. Please clarify this inconsistency.

FPL Response:

The original marked up TS changes were in error. The revised TS changes are contained in Attachment 3.

References

1. Deleted.
2. Deleted.
3. Deleted.
4. Deleted.
5. ASME OM-1987, Part 1, "Requirements for Inservice Performance Testing of Nuclear Power Plant Pressure Relief Devices."
6. Deleted.
7. Deleted.
8. NRC Letter Dated May 4, 2000, "St. Lucie Plant, Units 1 and 2, Request for Additional Information Regarding the Main Steam and Pressurizer Code Safety Valve Setpoint Setting (TAC NOS. MA8109 AND MA8110)."
9. St. Lucie Unit 1 Updated Final Safety Analysis Report, Amendment 17.
10. EMF-96-135, "St. Lucie Unit 1 Chapter 15 Event Review and Analysis for 30% Steam Generator Tube Plugging," May 1996 (included in the submittal of L-96-141, approved in amendment # 145).
11. L-99-112, J. A. Stall (FPL) to Document Control Desk (NRC), "St. Lucie Unit 1, Docket No. 50-335, SBLOCA Evaluation Model 30-Day 10 CFR 50.46 Report" May 20, 1999.

12. L-2000-58, R. S. Kundalkar (FPL) to Document Control Desk (NRC), "St. Lucie Units 1 and 2, Docket Nos. 50-335 and 50-389, Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Reactors: 10 CFR 50.46 Annual Report," March 6, 2000.

13. L-98-308, J. A. Stall (FPL) to Document Control Desk (NRC), "St. Lucie Unit 2 Docket No. 50-389, Proposed License Amendment: Cycle 12 Reload Process Improvement," December 18, 1998.

14. L-99-195, J. A. Stall (FPL) to Document Control Desk (NRC), "St. Lucie Unit 2, Docket No. 50-389, Proposed License Amendment: Cycle 12 Reload Process Improvement, Responses to Request for Additional Information," September 13, 1999.

15. ANF-84-73(P)(A), "Advanced Nuclear Fuels Methodology for Pressurized Water Reactors: Analysis of Chapter 15 Events," October 1990.

16. XN-NF-82-49(P)(A), Revision 1 Supplement 1, "Exxon Nuclear Company Evaluation Model Revised EXEM PWR Small Break Model," December 1994.

17. Letter, A. E. Scherer Enclosure 1-P to LD-82-001, "CESEC-Digital Simulation of a Combustion Engineering Nuclear Steam Supply System," December 1981.

18. CEN-121(B)-P, "CEAW, Method of Analyzing Sequential Control Element Assembly Group Withdrawal Event for Analog Protected Systems," November 1979.

19. CENPD-137, Supplement 1-P, 'Calculative Methods for the C-E Small Break LOCA Evaluation Model," January 1977.

20. CENPD-133, Supplement 3-P, "CEFLASH-4AS, A Computer Program for the Reactor Blowdown Analysis of the Small Break Loss of Coolant Accident," January 1977.

21. Letter, K. Kniel (NRC) to A. E. Scherer (CE), "Evaluation of Topical Reports CENPD-133, Supplement 3-P and CENPD-137, Supplement 1-P," September 1977.

Attachment 2 to FPL Letter L-2000-141

ST. LUCIE UNIT 1 MARKED UP TECHNICAL SPECIFICATION PAGES

TS Page IV

TS Page 3/4 4-2

*TS Page 3/4 4-3

TS Page B-3/4 4-1

TS Page B-3/4 4-2

*TS Page 3/4 7-1

*TS Page 3/4 7-3

TS Page B-3/4 7-2

* - The RAI response changes this TS Mark Up

LIMITING CONDITIONS FOR OPERATION AND SURVEILLANCE REQUIREMENTS

LIMITING CONDITION FOR OPERATION

3.4.2 A minimum of one pressurizer code safety valve shall be OPERABLE with a lift setting of 2500 PSIA ± 1%.

APPLICABILITY: MODES 4 and 5.

ACTION:

With no pressurizer code safety valve OPERABLE, immediately suspend all operations involving positive reactivity changes and place an OPERABLE shutdown cooling loop into operation.

Deleted

SURVEILLANCE REQUIREMENTS

4.4.2 No additional Surveillance Requirements other than those required by the Inservice Testing Program.

LIMITING CONDITION FOR OPERATION

3.4.3 All pressurizer code safety valves shall be OPERABLE with a lift setting of ~~2500 PSIA ± 1%.~~ ≥ 2422.8 psig and ≤ 2560.3 psig

APPLICABILITY: MODES ~~1, 2 and 3.~~ 1, 2, 3, and 4 with all RCS cold leg temperatures > 281°F

ACTION:

~~With one pressurizer code safety valve inoperable, either restore the inoperable valve to OPERABLE status within 15 minutes or be in HOT SHUTDOWN within 12 hours.~~

Insert 1

SURVEILLANCE REQUIREMENTS

4.4.3 ~~No additional Surveillance Requirements other than those required by the Inservice Testing Program.~~

Insert 2

BASES

3/4.4.1 REACTOR COOLANT LOOPS AND COOLANT CIRCULATION

The plant is designed to operate with both reactor coolant loops and associated reactor coolant pumps in operation, and maintain DNBR above the DNBR limit during all normal operations and anticipated transients. In MODES 1 and 2 with one reactor coolant loop not in operation, this specification requires that the plant be in at least HOT STANDBY within 1 hour.

In MODE 3, a single reactor coolant loop provides sufficient heat removal capability for removing decay heat; however, single failure considerations require that two loops be OPERABLE.

In MODE 4, and in MODE 5 with reactor coolant loops filled, a single reactor coolant loop or shutdown cooling loop provides sufficient heat removal capability for removing decay heat; but single failure considerations require that at least two loops (either shutdown cooling or RCS) be OPERABLE.

In MODE 5 with reactor coolant loops not filled, a single shutdown cooling loop provides sufficient heat removal capability for removing decay heat; but single failure considerations and the unavailability of the steam generators as a heat removing component, require that at least two shutdown cooling loops be OPERABLE.

The operation of one Reactor Coolant Pump or one shutdown cooling pump provides adequate flow to ensure mixing, prevent stratification and produce gradual reactivity changes during boron concentration reductions in the Reactor Coolant System. The reactivity change rate associated with boron reductions will, therefore, be within the capability of operator recognition and control.

The restrictions on starting a Reactor Coolant Pump are provided to prevent RCS pressure transients, caused by energy additions from the secondary system, which could exceed the limits of Appendix G to 10 CFR 50. The RCS will be protected against overpressure transients and will not exceed the limits of Appendix G by restricting starting of the Reactor Coolant Pumps to when the secondary water temperature of each steam generator is less than 30°F above each of the Reactor Coolant System cold leg temperatures.

~~3/4.4.2 and~~ 3/4.4.3 SAFETY VALVES

The pressurizer code safety valves operate to prevent the RCS from being pressurized above its Safety Limit of 2750 psia. Each safety valve is designed to relieve 2×10^5 lbs per hour of saturated steam at the valve setpoint. The relief capacity of a single safety valve is adequate to relieve any overpressure condition which could occur during shutdown. In the event that no safety valves are OPERABLE, an operating shutdown cooling loop, connected to the RCS, provides overpressure relief capability and will prevent RCS overpressurization.

3/4.4.2 and 3/4.4.3 SAFETY VALVES (Continued)

During operation, all pressurizer code safety valves must be OPERABLE to prevent the RCS from being pressurized above its safety limit of 2750 psia. The combined relief capacity of these valves is sufficient to limit the Reactor Coolant System pressure to within its Safety Limit of 2750 psia following a complete loss of turbine generator load while operating at RATED THERMAL POWER and assuming no reactor trip until the first Reactor Protective System trip setpoint (Pressurizer Pressure-High) is reached (i.e., no credit is taken for a direct reactor trip on the loss of turbine) and also assuming no operation of the pressurizer power operated relief valve or steam dump valves.

~~Demonstration of the safety valves' lift settings will occur only during shutdown and will be performed in accordance with the provisions of the Inservice Testing Program.~~

Insert 3

3/4.4.4 PRESSURIZER

A steam bubble in the pressurizer ensures that the RCS is not a hydraulically solid system and is capable of accommodating pressure surges during operation. The steam bubble also protects the pressurizer code safety valves and power operated relief valve against water relief. The power operated relief valve and steam bubble function to relieve RCS pressure during all design transients. Operation of the power operated relief valve in conjunction with a reactor trip on a Pressurizer-Pressure-High signal minimizes the undesirable opening of the spring-loaded pressurizer code safety valves. The required pressuzier heater capacity is capable of maintaining natural circulation sub-cooling. Operability of the heaters, which are powered by a diesel generator bus, ensures ability to maintain pressure control even with loss of offsite power.

3/4.4.5 STEAM GENERATORS

One OPERABLE steam generator provides sufficient heat removal capability to remove decay heat after a reactor shutdown. The requirement for two steam generators capable of removing decay heat, combined with the requirements of Specifications 3.7.1.1, 3.7.1.2 and 3.7.1.3 ensures adequate decay heat removal capabilities for RCS temperatures greater than 325°F if one steam generator becomes inoperable due to single failure considerations. Below 325°F, decay heat is removed by the shutdown cooling system.

The Surveillance Requirements for inspection of the steam generator tubes ensure that the structural integrity of this portion of the RCS will be maintained. The program for inservice inspection of steam generator tubes is based on a modification of Regulatory Guide 1.83, Revision 1. Inservice inspection of steam generator tubing is essential in order to maintain surveillance of the conditions of the tubes in the event that there is evidence of mechanical damage or progressive degradation due to design, manufacturing errors, or in-service conditions that lead to corrosion. Inservice inspection of Steam generator tubing also provides a means of characterizing the nature and cause of any tube degradation so that corrective measures can be taken.

SAFETY VALVES

LIMITING CONDITION FOR OPERATION

3.7.1.1 All main steam line code safety valves shall be OPERABLE with lift settings as specified in Table 4.7-1.

APPLICABILITY: MODES 1, 2 and 3.

ACTION:

a. With both reactor coolant loops and associated steam generators in operation and with one or more main steam line code safety valves inoperable, operation in MODES 1, 2 and 3 may proceed provided that within 4 hours, either the inoperable valve is restored to OPERABLE status or the Power Level-High trip setpoint is reduced per Table 3.7-1; otherwise, be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

b. The provisions of Specification 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.7.1.1 ~~No additional Surveillance Requirements other than those required by the Inservice Testing Program.~~

Insert 4

TABLE 4.7-1

STEAM LINE SAFETY VALVES PER LOOP

VALVE NUMBER			LIFT SETTING ~~(± 1%)~~ (+1% to -3%)	~~ORIFICE SIZE~~
	Header A	Header B		
a.	8201	8205	~~1000 psia~~ $\geq$ 955.3 psig and $\leq$ 995.3 psig	~~16 in.^{2}~~
b.	8202	8206	~~1000 psia~~ "	~~16 in.^{2}~~
c.	8203	8207	~~1000 psia~~ "	~~16 in.^{2}~~
d.	8204	8208	~~1000 psia~~ "	~~16 in.^{2}~~
e.	8209	8213	~~1040 psia~~ $\geq$ 994.1 psig and $\leq$ 1035.7 psig	~~16 in.^{2}~~
f.	8210	8214	~~1040 psia~~ "	~~16 in.^{2}~~
g.	8211	8215	~~1040 psia~~ "	~~16 in.^{2}~~
h.	8212	8216	~~1040 psia~~ "	~~16 in.^{2}~~

106.5 = Power Level-High Trip Setpoint for two loop operation

X = Total relieving capacity of all safety valves per steam line in lbs/hour (6.192×10^6 lbs/hr.)

Y = Maximum relieving capacity of any one safety valve ~~in~~ lbs/hour (7.74×10^5 lbs/hr.)

Insert 5

3/4.7.1.2 AUXILIARY FEEDWATER PUMPS

The OPERABILITY of the auxiliary feedwater pumps ensures that the Reactor Coolant System can be cooled down to less than 325°F from normal operating conditions in the event of a total loss of off-site power.

Any two of the three auxiliary feedwater pumps have the required capacity to provide sufficient feedwater flow to remove reactor decay heat and reduce the RCS temperature to 325°F where the shutdown cooling system may be placed into operation for continued cooldown.

3/4.7.1.3 CONDENSATE STORAGE TANK

The OPERABILITY of the condensate storage tank with the minimum water volume ensures that sufficient water is available for cooldown of the Reactor Coolant System to less than 325°F in the event of a total loss of off-site power. The minimum water volume is sufficient to maintain the RCS at HOT STANDBY conditions for 8 hours with steam discharge to atmosphere.

3/4.7.1.4 ACTIVITY

The limitations on secondary system specific activity ensure that the resultant off-site radiation dose will be limited to a small fraction of 10 CFR Part 100 limits in the event of a steam line rupture. The dose calculations for an assumed steam line rupture include the effects of a coincident 1.0 GPM primary to secondary tube leak in the steam generator of the affected steam line and a concurrent loss of offsite electrical power. These values are consistent with the assumptions used in the accident analyses.

Insert 1

a. With one pressurizer code safety valve inoperable, either restore the inoperable valve to OPERABLE status within 15 minutes or be in HOT STANDBY within 6 hours and in HOT SHUTDOWN within the next 6 hours.

b. With two or more pressurizer code safety valves inoperable, be in HOT STANDBY within 6 hours and in HOT SHUTDOWN with all RCS cold leg temperatures # 281°F within the next 6 hours.

Insert 2

Verify each pressurizer code safety valve is OPERABLE in accordance with the Inservice Testing Program. Following testing, as-left lift settings shall be within ∀1% of 2500 psia.

Insert 3

Surveillance Requirements are specified in the Inservice Testing Program. Pressurizer code safety valves are to be tested in accordance with the requirements of Section XI of the ASME Code, which provides the activities and the frequency necessary to satisfy the Surveillance Requirements. No additional requirements are specified.

The pressurizer code safety valve as-found setpoint is 2500 psia +3/-2.5% for OPERABILITY; however, the valves are reset to 2500 psia ∀1% during the Surveillance to allow for drift. The LCO is expressed in units of psig for consistency with implementing procedures.

Insert 4

Verify each main steam line code safety valve is OPERABLE in accordance with the Inservice Testing Program. Following testing, as-left lift settings shall be within ∀1% of 1000 psia for valves 8201 through 8208, and within ∀1% of 1040 psia for valves 8209 through 8216 specified in Table 4.7-1.

Insert 5

Surveillance Requirement 4.7.1.1 verifies the OPERABILITY of the MSSVs by the verification of each MSSV lift setpoint in accordance with the Inservice Testing Program. The MSSV setpoints are 1000 psia +1/-3% (4 valves each header) and 1040 psia +1/-3% (4 valves each header) for OPERABILITY; however, the valves are reset to 1000 psia ∀1% and 1040 psia ∀1%, respectively, during the Surveillance to allow for drift. The LCO is expressed in units of psig for consistency with implementing procedures.

The provisions of Specification 3.0.4 do not apply. This allows entry into and operation in MODE 3 prior to performing the Surveillance Requirement so that the MSSVs may be tested under hot conditions.

Attachment 3 to FPL Letter L-2000-141

ST. LUCIE UNIT 2 MARKED UP TECHNICAL SPECIFICATION PAGES

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* - The RAI response changes this TS Mark Up

INDEX

LIMITING CONDITION FOR OPERATION AND SURVEILLANCE REQUIREMENTS

3/4.4.2 SAFETY VALVES

SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.4.2.1 A minimum of one pressurizer code safety valve shall be OPERABLE with a lift setting of 2500 psia ± 1%. *

APPLICABILITY: MODES 4 and 5.

ACTION:

With no pressurizer code safety valve OPERABLE, immediately suspend all operations involving positive reactivity changes and place an OPERABLE shutdown cooling loop into operation.

DELETED

SURVEILLANCE REQUIREMENTS

4.4.2.1 No additional Surveillance Requirements other than those required by the Inservice Testing Program.

* The lift setting pressure shall correspond to ambient conditions of the valve at nominal operating temperature and pressure.

OPERATING

LIMITING CONDITION FOR OPERATION

3.4.2.2 All pressurizer code safety valves shall be OPERABLE with a lift setting of ~~2500 psia ± 1%.~~* ≥ 2435.3 psig and ≤ 2535.3 psig *

APPLICABILITY: MODES 1, ~~2, and~~ 3, and 4 with all RCS cold leg temperatures > 230°F

ACTION:

a. With one pressurizer code safety valve inoperable, either restore the inoperable valve to OPERABLE status within 15 minutes or be in ~~at least~~ HOT STANDBY within 6 hours and in HOT SHUTDOWN within the ~~following~~ next 6 hours.

Insert 1

SURVEILLANCE REQUIREMENTS

4.4.2.2 ~~No additional Surveillance Requirements other than those required by the Inservice Testing Program.~~

Insert 2

* The lift setting pressure shall correspond to ambient conditions of the valve at nominal operating temperature and pressure.

SAFETY VALVES (Continued)

During operation, all pressurizer code safety valves must be OPERABLE to prevent the RCS from being pressurized above its safety limit of 2750 psia. The combined relief capacity of these valves is sufficient to limit the system pressure to within its Safety Limit of 2750 psia following a complete loss of turbine generator load while operating at RATED THERMAL POWER and assuming no reactor trip until the first Reactor Protective System trip setpoint (Pressurizer Pressure-High) is reached (i.e., no credit is taken for a direct reactor trip on the loss of turbine) and also assuming no operation of the pressurizer power-operated relief valve or steam dump valves.

~~Demonstration of the safety valves' lift settings will occur only during shutdown and will be performed in accordance with the provisions of the Inservice Testing Program.~~

Insert 3

3/4.4.3 PRESSURIZER

An OPERABLE pressurizer provides pressure control for the Reactor Coolant System during operations with both forced reactor coolant flow and with natural circulation flow. The minimum water level in the pressurizer assures the pressurizer heaters, which are required to achieve and maintain pressure control, remain covered with water to prevent failure, which could occur if the heaters were energized uncovered. The maximum water level in the pressurizer ensures that this parameter is maintained within the envelope of operation assumed in the safety analysis. The maximum water level also ensures that the RCS is not a hydraulically solid system and that a steam bubble will be provided to accommodate pressure surges during operation. The steam bubble also protects the pressurizer code safety valves against water relief. The requirement to verify that on an Engineered Safety Features Actuation test signal concurrent with a loss of offsite power the pressurizer heaters are automatically shed from the emergency power sources is to ensure that the non-Class 1E heaters do not reduce the reliability of or overload the emergency power source. The requirement that a minimum number of pressurizer heaters be OPERABLE enhances the capability to control Reactor Coolant System pressure and establish and maintain natural circulation.

SAFETY VALVES

LIMITING CONDITION FOR OPERATION

3.7.1.1 All main steam line code safety valves shall be OPERABLE with lift settings ~~and orifice sizes~~ as shown in Table 3.7-2.

APPLICABILITY: MODES 1, 2 and 3.

ACTION:

a. With both reactor coolant loops and associated steam generators in operation and with one or more main steam line code safety valves inoperable, operation in MODES 1, 2 and 3 may proceed provided that, within 4 hours, either the inoperable valve is restored to OPERABLE status or the Power Level-High trip setpoint is reduced per Table 3.7-1; otherwise, be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

b. The provisions of Specification 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.7.1.1 ~~No additional Surveillance Requirements other than those required by the Inservice Testing Program.~~

Insert 4

TABLE 3.7-2

STEAM LINE SAFETY VALVES PER LOOP

VALVE NUMBER			LIFT SETTING (~~± 1%~~) (+1% to -3%)	~~ORIFICE SIZE~~
	Header A	Header B		
a.	8201	8205	~~1000 psia~~ $\geq$ 955.3 psig and $\leq$ 995.3 psig	~~16 in.^{2}~~
b.	8202	8206	~~1000 psia~~ "	~~16 in.^{2}~~
c.	8203	8207	~~1000 psia~~ "	~~16 in.^{2}~~
d.	8204	8208	~~1000 psia~~ "	~~16 in.^{2}~~
e.	8209	8213	~~1040 psia~~ $\geq$ 994.1 psig and $\leq$ 1035.7 psig	~~16 in.^{2}~~
f.	8210	8214	~~1040 psia~~ "	~~16 in.^{2}~~
g.	8211	8215	~~1040 psia~~ "	~~16 in.^{2}~~
h.	8212	8216	~~1040 psia~~ "	~~16 in.^{2}~~

3/4.7.1 TURBINE CYCLE

3/4.7.1.1 SAFETY VALVES

The OPERABILITY of the main steam line code safety valves ensures that the secondary system pressure will be limited to within 110% (1100 psia) of its design pressure of 1000 psia during the most severe anticipated system operational transient. The maximum relieving capacity is associated with a turbine trip from 100% RATED THERMAL POWER coincident with an assumed loss of condenser heat sink (i.e., no steam bypass to the condenser).

The specified valve lift settings and relieving capacities are in accordance with the requirements of Section III of the ASME Boiler and Pressure Vessel Code, 1971 Edition, and ASME Code for Pumps and Valves, Class II. The total relieving capacity for all valves on all of the steam lines is 12.49×10^6 lbs/hr which is 103.8% of the total secondary steam flow of 12.03×10^6 lbs/hr at 100% RATED THERMAL POWER. A minimum of two OPERABLE safety valves per steam generator ensures that sufficient relieving capacity is available for removing decay heat.

STARTUP and/or POWER OPERATION is allowable with safety valves inoperable within the limitations of the ACTION requirements on the basis of the reduction in secondary system steam flow and THERMAL POWER required by the reduced reactor trip settings of the Power Level-High channels. The reactor trip setpoint reductions are derived on the following bases:

For two loop operation:

$$SP = \left[\frac{(X) - (Y)(V)}{X} \times (107.0)\right] - 0.9$$

where:

SP = reduced reactor trip setpoint in percent of RATED THERMAL POWER

V = maximum number of inoperable safety valves per steam line

107.0 = Power Level-High Trip Setpoint for two loop operation

0.9 = Equipment processing uncertainty

X = Total relieving capacity of all safety valves per steam line in lbs/hour (6.247×10^6 lbs/hr)

Y = Maximum relieving capacity of any one safety valve in lbs/hour (7.74×10^5 lbs/hr)

Insert S

Insert 1

b. With two or more pressurizer code safety valves inoperable, be in HOT STANDBY within 6 hours and in HOT SHUTDOWN with all RCS cold leg temperatures # 230°F within the next 6 hours.

Insert 2

Verify each pressurizer code safety valve is OPERABLE in accordance with the Inservice Testing Program. Following testing, as-left lift settings shall be within ∀1% of 2500 psia.

Insert 3

Surveillance Requirements are specified in the Inservice Testing Program. Pressurizer code safety valves are to be tested in accordance with the requirements of Section XI of the ASME Code, which provides the activities and the frequency necessary to satisfy the Surveillance Requirements. No additional requirements are specified.

The pressurizer code safety valve as-found setpoint is 2500 psia ∀2% for OPERABILITY; however, the valves are reset to 2500 psia ∀1% during the Surveillance to allow for drift. The LCO is expressed in units of psig for consistency with implementing procedures.

Insert 4

Verify each main steam line code safety valve is OPERABLE in accordance with the Inservice Testing Program. Following testing, as-left lift settings shall be within ∀1% of 1000 psia for valves 8201 through 8208, and within ∀1% of 1040 psia for valves 8209 through 8216 specified in Table 3.7-2.

Insert 5

Surveillance Requirement 4.7.1.1 verifies the OPERABILITY of the MSSVs by the verification of each MSSV lift setpoint in accordance with the Inservice Testing Program. The MSSV setpoints are 1000 psia +1/-3% (4 valves each header) and 1040 psia +1/-3% (4 valves each header) for OPERABILITY; however, the valves are reset to 1000 psia ∀1% and 1040 psia ∀1%, respectively, during the Surveillance to allow for drift. The LCO is expressed in units of psig for consistency with implementing procedures.

The provisions of Specification 3.0.4 do not apply. This allows entry into and operation in MODE 3 prior to performing the Surveillance Requirement so that the MSSVs may be tested under hot condition.