DCR 616

November 9, 1984

Docket Nos. 50-389

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Mr. J. W. Williams, Jr.
Vice President
Nuclear Energy Department
Florida Power & Light Company
P. O. Box 14000
Juno Beach, Florida 33408

Dear Mr. Williams:

The Commission has issued the enclosed Amendment No. 8 to Facility Operating License No. NPF-16 for the St. Lucie Plant, Unit No. 2. The amendment consists of changes to the Technical Specifications in response to your application dated June 4, 1984.

The amendment revises the technical specifications for Cycle 2 operation of St. Lucie 2.

A copy of the related Safety Evaluation is also enclosed. The notice of issuance will be included in the Commission's next monthly Federal Register notice.

We would like to note that the staff's Safety Evaluation references two submittals which are due to us before Cycle 2 startup. One submittal deals with your current license condition number 2.C.5 which states "Prior to startup following the first refueling outage, the licensees shall provide an analysis and/or make hardware modifications to assure that the shoulder gap clearance between fuel rods and fuel assembly end fittings is adequate." This is discussed in more detail in Section 2.1 of the staff's Safety Evaluation. By letter dated November 8, 1984 you provided this analysis and we consider this commitment has been met. The other report deals with formal documentation regarding the justification for the proposed 3.5 psig containment isolation actuation signal setpoint value. This is discussed in more detail in Section 9.2 of the Staff's Evaluation. By letter dated October 29, 1984, you provided the documentation, and we consider that this commitment has been met.

Sincerely,

/S/

James R. Miller, Chief
Operating Reactors Branch #3
Division of Licensing

Enclosures:
1. Amendment No. 8 to NPF-16
2. Safety Evaluation

cc w/enclosures:
See next page

ORB#3:DL	** ORB#3:DL	** ORB#3:DL	**OELD	**AD:OR:DL
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Sincerely,

Donald E. Sells, Project Manager
Operating Reactors Branch #3
Division of Licensing

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1. Amendment No. to NPF-16
2. Safety Evaluation

cc w/enclosures:
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Florida Power & Light Company

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Executive Office of the Governor
The Capitol Building
Tallahassee, Florida 32301

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D. C. 20555

FLORIDA POWER & LIGHT COMPANY

ORLANDO UTILITIES COMMISSION OF

THE CITY OF ORLANDO, FLORIDA

AND

FLORIDA MUNICIPAL POWER AGENCY

DOCKET NO. 50-389

ST. LUCIE PLANT UNIT NO. 2

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 8
License No. NPF-16

1. The Nuclear Regulatory Commission (the Commission) has found that:

   A. The application for amendment by Florida Power & Light Company, et al., (the licensee) dated June 4, 1984, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act) and the Commission's rules and regulations set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, the provisions of the Act, and the rules and regulations of the Commission;

   C. There is reasonable assurance (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations;

   D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

2. Accordingly, Facility Operating License No. NPF-16 is amended by changes to the Technical Specifications as indicated in the attachment to this license amendment, and by amending paragraph 2.C.2 to read as follows:

   2. Technical Specifications

      The Technical Specifications contained in Appendices A and B, as revised through Amendment No. 8 , are hereby incorporated in the license. The licensee shall operate the facility in accordance with the Technical Specifications.

3. This license amendment is effective as of the date of its issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

James R. Miller, Chief
Operating Reactors Branch #3
Division of Licensing

Attachment:
Changes to the Technical
Specifications

Date of Issuance: November 9, 1984

ATTACHMENT TO LICENSE AMENDMENT NO. 8

FACILITY OPERATING LICENSE NO. NPF-16

DOCKET NO. 50-389

Remove and replace the following pages of the Appendix A Technical Specifications with the attached pages. The revised pages are identified by amendment number and contain vertical lines indicating the area of change. The corresponding overleaf pages are provided to maintain document completeness.

Remove	Insert	Remove	Insert
XXI	XXI	3/4 7-1	3/4 7-1
XXII	XXII	3/4 7-2	3/4 7-2
XXIII	XXIII	3/4 7-3	3/4 7-3
XXIV	XXIV	3/4 7-10	3/4 7-10
XXV	XXV	B 3/4 1-1	B 3/4 1-1
2-1	2-1	B 3/4 1-2	B 3/4 1-2
2-3	2-3	B 3/4 1-4	B 3/4 1-4
2-4	2-4	B 3/4 2-2	B 3/4 2-2
2-5	2-5	B 3/4 2-3	B 3/4 2-3
2-9	2-9	B 3/4 7-1	B 3/4 7-1
2-10	2-10	5-1	5-1
B 2-1	B 2-1	5-3	5-3
B 2-2	B 2-2		
B 2-4	B 2-4		
3/4 1-3	3/4 1-3		
3/4 1-8	3/4 1-8		
3/4 1-10	3/4 1-10		
3/4 1-12	3/4 1-12		
3/4 1-14	3/4 1-14		
3/4 1-17	3/4 1-17		
3/4 1-18	3/4 1-18		
3/4 1-19	3/4 1-19		
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2.0 SAFETY LIMITS AND LIMITING SAFETY SYSTEM SETTINGS

2.1 SAFETY LIMITS

2.1.1 REACTOR CORE

DNBR

2.1.1.1 The combination of THERMAL POWER, pressurizer pressure, and maximum cold leg coolant temperature shall not exceed the limits shown on Figure 2.1-1.

APPLICABILITY: MODES 1 and 2.

ACTION:

Whenever the combination of THERMAL POWER, pressurizer pressure and maximum cold leg coolant temperature has exceeded the limits shown on Figure 2.1-1, be in HOT STANDBY within 1 hour, and comply with the requirements of Specification 6.7.1.

PEAK LINEAR HEAT RATE

2.1.1.2 The peak linear heat rate of the fuel shall be maintained less than or equal to 22.0 kW/ft (value corresponding to centerline fuel melt).

APPLICABILITY: MODES 1 and 2.

ACTION:

Whenever the peak linear heat rate of the fuel has exceeded 22.0 kW/ft (value corresponding to centerline fuel melt), be in HOT STANDBY within 1 hour, and comply with the requirements of Specification 6.7.1.

REACTOR COOLANT SYSTEM PRESSURE

2.1.2 The Reactor Coolant System pressure shall not exceed 2750 psia.

APPLICABILITY: MODES 1, 2, 3, 4, and 5.

ACTION:

MODES 1 and 2

Whenever the Reactor Coolant System pressure has exceeded 2750 psia, be in HOT STANDBY with the Reactor Coolant System pressure within its limit within 1 hour, and comply with the requirements of Specification 6.7.1.

MODES 3, 4 and 5

Whenever the Reactor Coolant System pressure has exceeded 2750 psia, reduce the Reactor Coolant System pressure to within its limit within 5 minutes, and comply with the requirements of Specification 6.7.1.

2.2 LIMITING SAFETY SYSTEM SETTINGS

REACTOR TRIP SETPOINTS

2.2.1 The reactor protective instrumentation setpoints shall be set consistent with the Trip Setpoint values shown in Table 2.2-1.

APPLICABILITY: As shown for each channel in Table 3.3-1.

ACTION:

With a reactor protective instrumentation setpoint less conservative than the value shown in the Allowable Values column of Table 2.2-1, declare the channel inoperable and apply the applicable ACTION statement requirement of Specification 3.3.1 until the channel is restored to OPERABLE status with its trip setpoint adjusted consistent with the Trip Setpoint value.

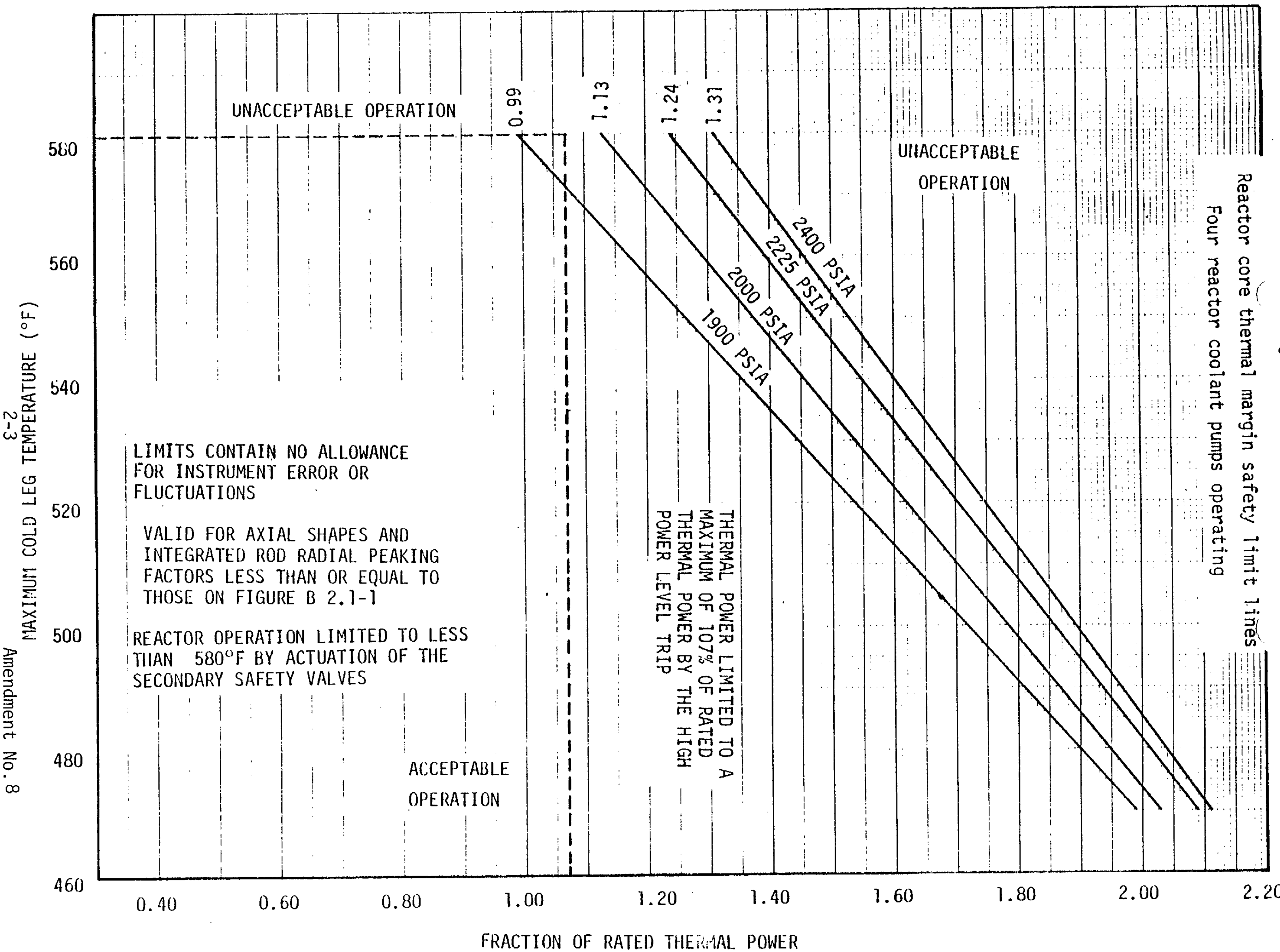


Figure 2.1-1

Reactor core thermal margin safety limit lines
Four reactor coolant pumps operating

TABLE 2.2-1

REACTOR PROTECTIVE INSTRUMENTATION TRIP SETPOINT LIMITS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
1. Manual Reactor Trip	Not Applicable	Not Applicable
2. Variable Power Level - High(1)		
Four Reactor Coolant Pumps Operating	≤ 9.61% above THERMAL POWER, with a minimum setpoint of 15% of RATED THERMAL POWER, and a maximum of ≤ 107.0% of RATED THERMAL POWER.	≤ 9.61% above THERMAL POWER, and a minimum setpoint of 15% of RATED THERMAL POWER and a maximum of ≤ 107.0% of RATED THERMAL POWER.
3. Pressurizer Pressure - High	≤ 2370 psia	≤ 2374 psia
4. Thermal Margin/Low Pressure		
Four Reactor Coolant Pumps Operating	Trip setpoint adjusted to not exceed the limit lines of Figures 2.2-3 and 2.2-4. Minimum value of 1900 psia.	Trip setpoint adjusted to not exceed the limit lines of Figures 2.2-3 and 2.2-4. Minimum value of 1900 psia.
5. Containment Pressure - High	≤ 3.0 psig	≤ 3.1 psig
6. Steam Generator Pressure - Low	≥ 626.0 psia (2)	≥ 621.0 psia (2)
7. Steam Generator Pressure(1) Difference - High (Logic in TM/LP Trip Unit)	≤ 120.0 psid	≤ 132.0 psid
8. Steam Generator Level - Low	≥ 39.5% (3)	≥ 39.1% (3)

TABLE 2.2-1 (Continued)

REACTOR PROTECTIVE INSTRUMENTATION TRIP SETPOINT LIMITS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
9. Local Power Density - High[5]	Trip setpoint adjusted to not exceed the limit lines of Figures 2.2-1 and 2.2-2.	Trip setpoint adjusted to not exceed the limit lines of Figures 2.2-1 and 2.2-2.
10. Loss of Component Cooling Water to Reactor Coolant Pumps-Low	$\geq$ 636 gpm**	$\geq$ 636 gpm
11. Reactor Protection System Logic	Not Applicable	Not Applicable
12. Reactor Trip Breakers	Not Applicable	Not Applicable
13. Rate of Change of Power - High[4]	$\leq$ 2.49 decades per minute	$\leq$ 2.49 decades per minute
14. Reactor Coolant Flow - Low	$\geq$ 95.4% of design Reactor Coolant flow with four pumps operating*	$\geq$ 94.9% of design Reactor Coolant flow with four pumps operating*
15. Loss of Load (Turbine) Hydraulic Fluid Pressure - Low[5]	$\geq$ 800 psig	$\geq$ 800 psig

*Design reactor coolant flow with four pumps operating is 363,000 gpm.

**10-minute time delay after relay actuation.

TABLE 2.2-1 (Continued)

REACTOR PROTECTIVE INSTRUMENTATION TRIP SETPOINT LIMITS

TABLE NOTATION

(1) Trip may be manually bypassed below 0.5% of RATED THERMAL POWER during testing pursuant to Special Test Exception 3.10.3; bypass shall be automatically removed when the THERMAL POWER is greater than or equal to 0.5% of RATED THERMAL POWER.

(2) Trip may be manually bypassed below 705 psig; bypass shall be automatically removed at or above 705 psig.

(3) % of the narrow range steam generator level indication.

(4) Trip may be bypassed below 10^{-4}% and above 15% of RATED THERMAL POWER; bypass shall be automatically removed when THERMAL POWER is $\geq 10^{-4}$% or $\leq$ 15% of RATED THERMAL POWER.

(5) Trip may be bypassed below 15% of RATED THERMAL POWER; bypass shall be automatically removed when THERMAL POWER is greater than or equal to 15% of RATED THERMAL POWER.

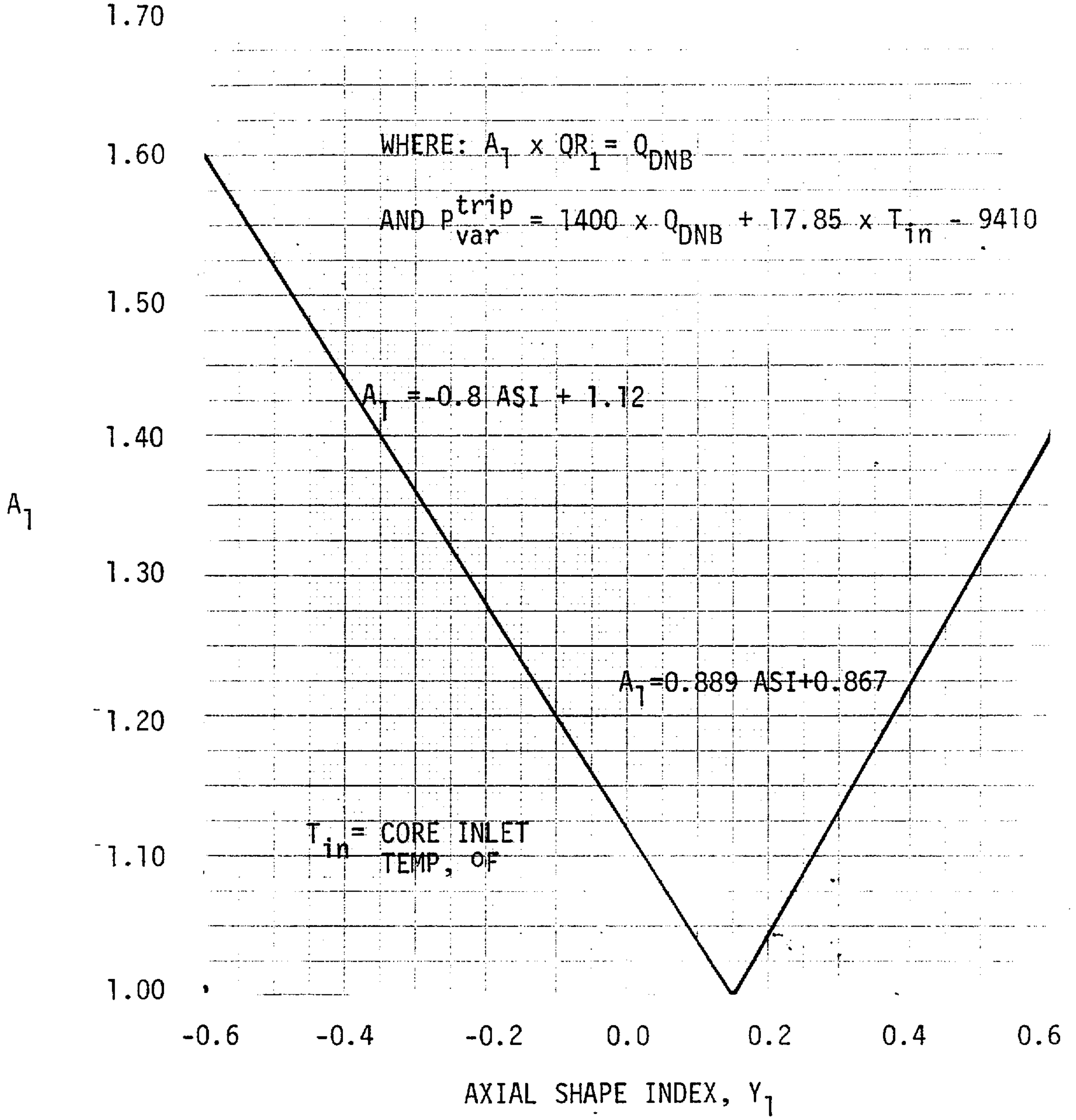


FIGURE 2.2-3

THERMAL MARGIN/LOW PRESSURE TRIP SETPOINT
PART 1 (Y_1 Versus A_1)

WHERE: $A_1 \times QR_1 = Q_{DNB}$

AND $P_{var}^{trip} = 1400 \times Q_{DNB} + 17.85 \times T_{in} - 9410$

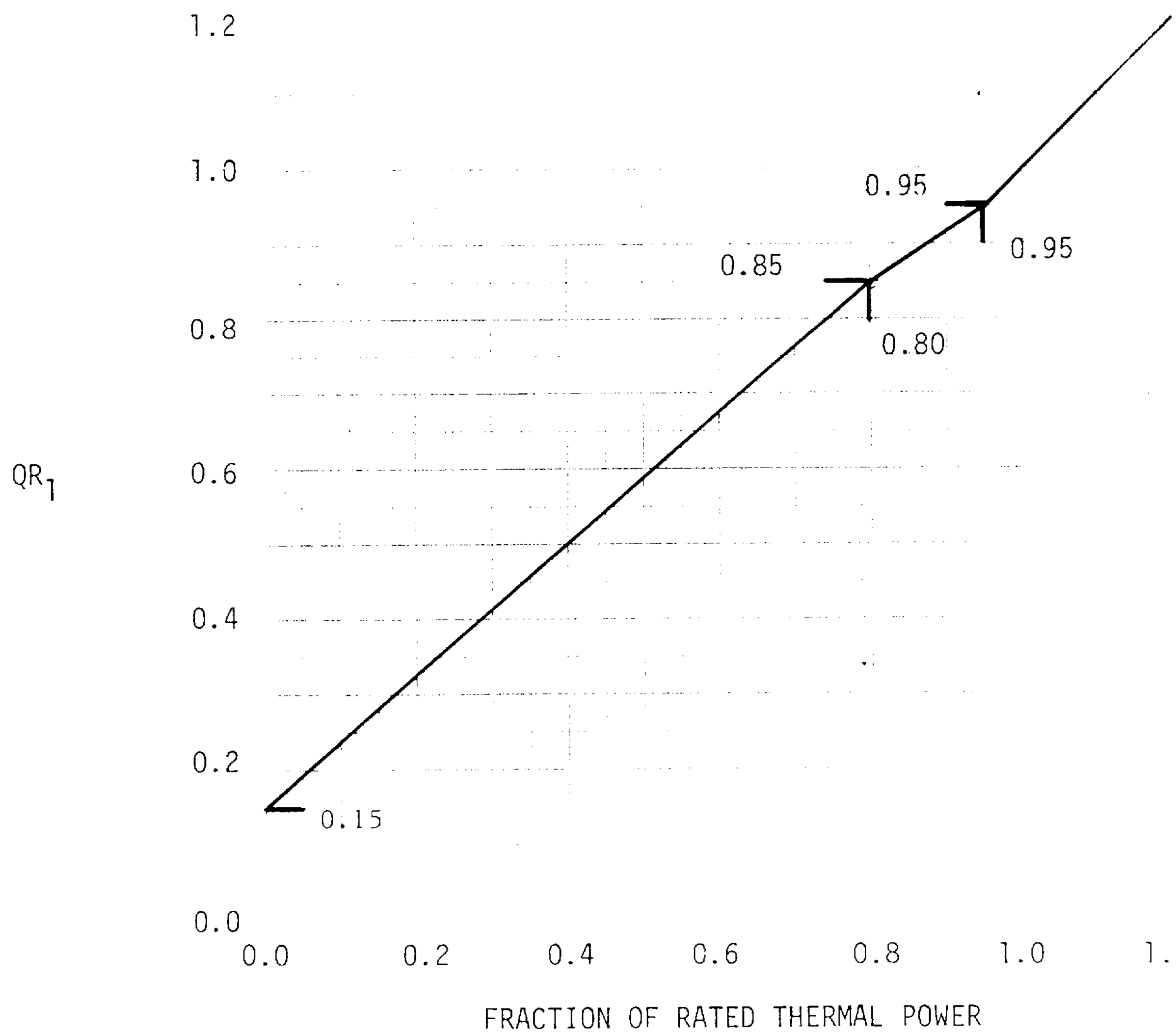


FIGURE 2.2-4

THERMAL MARGIN/LOW PRESSURE TRIP SETPOINT
PART 2 (FRACTION OF RATED THERMAL POWER VERSUS QR_1)

2.1 SAFETY LIMITS

BASES

2.1.1 REACTOR CORE

The restrictions of this safety limit prevent overheating of the fuel cladding and possible cladding perforation which would result in the release of fission products to the reactor coolant. Overheating of the fuel is prevented by maintaining the steady-state peak linear heat rate below the level at which centerline fuel melting will occur. Overheating of the fuel cladding is prevented by restricting fuel operation to within the nucleate boiling regime where the heat transfer coefficient is large and the cladding surface temperature is slightly above the coolant saturation temperature.

Operation above the upper boundary of the nucleate boiling regime could result in excessive cladding temperatures because of the onset of departure from nucleate boiling (DNB) and the resultant sharp reduction in heat transfer coefficient. DNB is not a directly measurable parameter during operation and therefore THERMAL POWER and Reactor Coolant Temperature and Pressure have been related to DNB through the CE-1 correlation. The CE-1 DNB correlation has been developed to predict the DNB heat flux and the location of DNB for axially uniform and non-uniform heat flux distributions. The local DNB heat flux ratio, DNBR, defined as the ratio of the heat flux that would cause DNB at a particular core location to the local heat flux, is indicative of the margin to DNB.

The minimum value of the DNBR during steady state operation, normal operational transients, and anticipated transients is limited to 1.28. This value is derived through a statistical combination of the system parameter probability distribution functions with the CE-1 DNB correlation uncertainty. This value corresponds to a 95% probability at a 95% confidence level that DNB will not occur and is chosen as an appropriate margin to DNB for all operating conditions.

The curves of Figure 2.1-1 show the loci of points of THERMAL POWER, Reactor Coolant System pressure and maximum cold leg temperature with four Reactor Coolant Pumps operating for which the minimum DNBR is no less than 1.28 for the family of axial shapes and corresponding radial peaks shown in Figure B 2.1-1. The limits in Figure 2.1-1 were calculated for reactor coolant inlet temperatures less than or equal to 580°F. The dashed line at 580°F coolant inlet temperature is not a safety limit; however, operation above 580°F is not possible because of the actuation of the main steam line safety valves which limit the maximum value of reactor inlet temperature. Reactor operation at THERMAL POWER levels higher than 112% of RATED THERMAL POWER is prohibited by the high power level trip setpoint sepcifed in Table 2.2-1. The area of safe operation is below and to the left of these lines.

The conditions for the Thermal Margin Safety Limit curves in Figure 2.1-1 to be valid are shown on the figure.

The Thermal Margin/Low Pressure and Local Power Density Trip Systems, in conjunction with Limiting Conditions for Operation, the Variable Overpower Trip and the Power Dependent Insertion Limits, assure that the Specified Acceptable Fuel Design Limits on DNB and Fuel Centerline Melt are not exceeded during normal operation and design basis Anticipated Oqeration Occurrences.

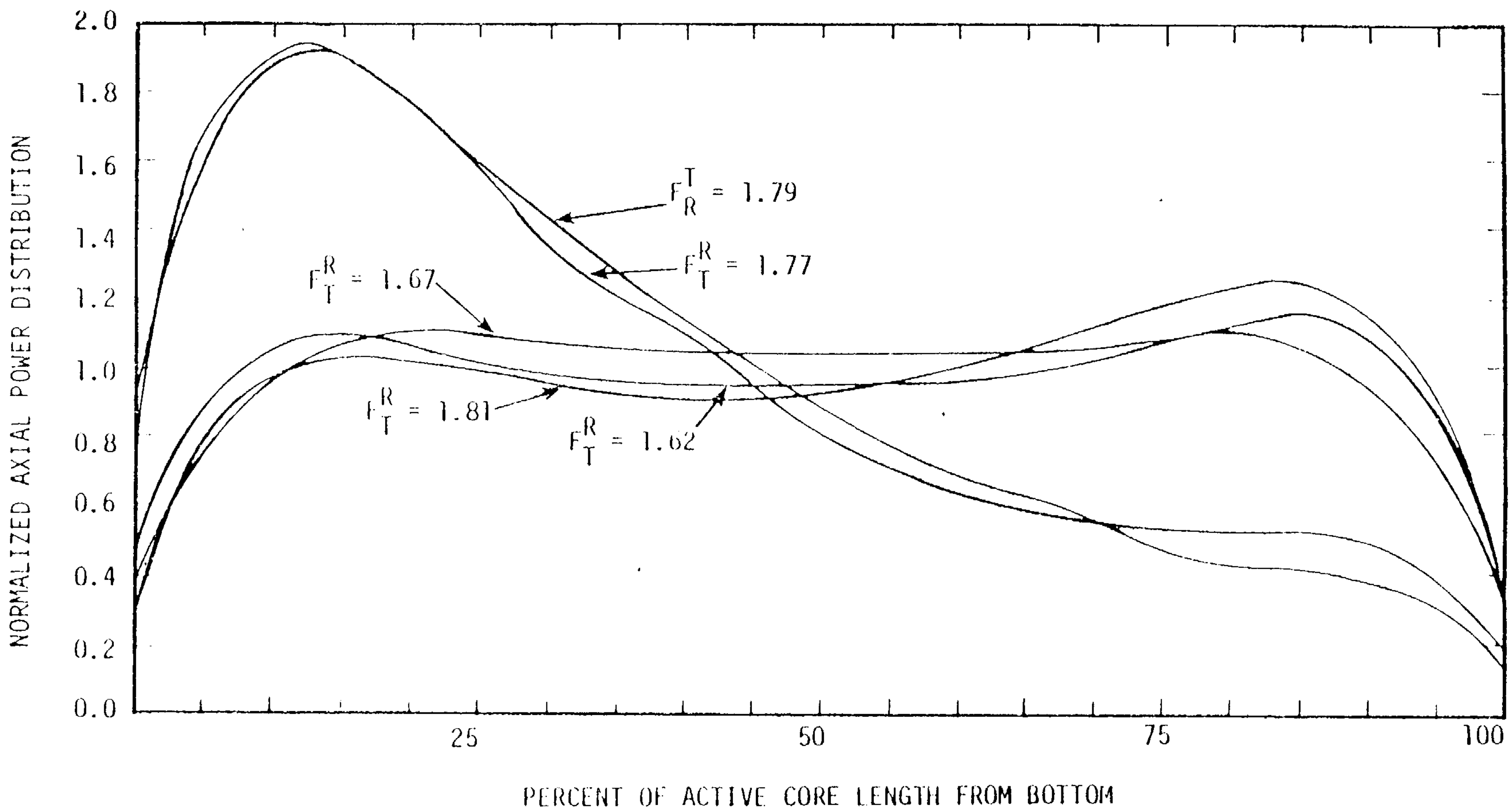


Figure B 2.1-1

Axial power distribution for thermal margin safety limits

2.1.2 REACTOR COOLANT SYSTEM PRESSURE

The restriction of this Safety Limit protects the integrity of the Reactor Coolant System from overpressurization and thereby prevents the release of radionuclides contained in the reactor coolant from reaching the containment atmosphere.

The Reactor Coolant System components are designed to Section III, 1971 Edition including Addenda to the Summer, 1973, of the ASME Code for Nuclear Power Plant Components which permits a maximum transient pressure of 110% (2750 psia) of design pressure. The Safety Limit of 2750 psia is therefore consistent with the design criteria and associated code requirements.

The entire Reactor Coolant System was hydrotested at 3125 psia to demonstrate integrity prior to initial operation.

2.2 LIMITING SAFETY SYSTEM SETTINGS

2.2.1 REACTOR TRIP SETPOINTS

The Reactor Trip Setpoints specified in Table 2.2-1 are the values at which the Reactor Trips are set for each functional unit. The Trip Setpoints have been selected to ensure that the reactor core and reactor coolant system are prevented from exceeding their Safety Limits during normal operation and design basis anticipated operational occurrences and to assist the Engineered Safety Features Actuation System in mitigating the consequences of accidents. Operation with a trip set less conservative than its Trip Setpoint but within its specified Allowable Value is acceptable on the basis that the difference between each Trip Setpoint and the Allowable Value is equal to or less than the drift allowance assumed for each trip in the safety analyses.

Manual Reactor Trip

The Manual Reactor Trip is a redundant channel to the automatic protective instrumentation channels and provides manual reactor trip capability.

Variable Power Level-High

A Reactor trip on Variable Overpower is provided to protect the reactor core during rapid positive reactivity addition excursions which are too rapid to be protected by a Pressurizer Pressure-High or Thermal Margin/Low Pressure Trip.

The Variable Power Level High trip setpoint is operator adjustable and can be set no higher than 9.61% above the indicated THERMAL POWER level. Operator action is required to increase the trip setpoint as THERMAL POWER is increased. The trip setpoint is automatically decreased as THERMAL POWER decreases. The trip setpoint has a maximum value of 107.0% of RATED THERMAL POWER and a minimum setpoint of 15.0% of RATED THERMAL POWER. Adding to this maximum value the possible variation in trip point due to calibration and instrument errors, the maximum actual steady-state THERMAL POWER level at which a trip would be actuated is 112% of RATED THERMAL POWER, which is the value used in the safety analyses.

Pressurizer Pressure-High

The Pressurizer Pressure-High trip, in conjunction with the pressurizer safety valves and main steam safety valves, provides Reactor Coolant System protection against overpressurization in the event of loss of load without reactor trip. This trip's setpoint is at less than or equal to 2375 psia which is below the nominal lift setting 2500 psia of the pressurizer safety valves and its operation minimizes the undesirable operation of the pressurizer safety valves.

Thermal Margin/Low Pressure

The Thermal Margin/Low Pressure trip is provided to prevent operation when the DNBR is less than 1.28.

The trip is initiated whenever the Reactor Coolant System pressure signal drops below either 1900 psia or a computed value as described below, whichever is higher. The computed value is a function of the higher of ΔT power or neutron power, reactor inlet temperature, the number of reactor coolant pumps operating and the AXIAL SHAPE INDEX. The minimum value of reactor coolant flow rate, the maximum AZIMUTHAL POWER TILT and the maximum CEA deviation permitted for continuous operation are assumed in the generation of this trip function. In addition, CEA group sequencing in accordance with Specifications 3.1.3.5 and 3.1.3.6 is assumed. Finally, the maximum insertion of CEA banks which can occur during any anticipated operational occurrence prior to a Power Level-High trip is assumed.

The Thermal Margin/Low Pressure trip setpoints are derived from the core safety limits through application of appropriate allowances for equipment response time measurement uncertainties and processing error. A safety margin is provided which includes: an allowance of 2.0% of RATED THERMAL POWER to compensate for potential power measurement error; an allowance of 3.0°F to compensate for potential temperature measurement uncertainty; and a further allowance of 91.0 psia to compensate for pressure measurement error and time delay associated with providing effective termination of the occurrence that exhibits the most rapid decrease in margin to the safety limit. The 91.0 psia allowance is made up of a 25.0 psia pressure measurement allowance and a 66.0 psia time delay allowance.

SHUTDOWN MARGIN - T_{avg} LESS THAN OR EQUAL TO 200°F

LIMITING CONDITION FOR OPERATION

3.1.1.2 The SHUTDOWN MARGIN shall be greater than or equal to 3.0% delta k/k.

APPLICABILITY: MODE 5.

ACTION:

With the SHUTDOWN MARGIN less than 3.0% delta k/k, immediately initiate and continue boration at greater than or equal to 40 gpm of a solution containing greater than or equal to 1720 ppm boron or equivalent until the required SHUTDOWN MARGIN is restored.

SURVEILLANCE REQUIREMENTS

4.1.1.2 The SHUTDOWN MARGIN shall be determined to be greater than or equal to 3.0% delta k/k:

a. Within 1 hour after detection of an inoperable CEA(s) and at least once per 12 hours thereafter while the CEA(s) is inoperable. If the inoperable CEA is immovable or untrippable, the above required SHUTDOWN MARGIN shall be increased by an amount at least equal to the withdrawn worth of the immovable or untrippable CEA(s).

b. At least once per 24 hours by consideration of the following factors:

   1. Reactor coolant system boron concentration,
   2. CEA position,
   3. Reactor coolant system average temperature,
   4. Fuel burnup based on gross thermal energy generation,
   5. Xenon concentration, and
   6. Samarium concentration.

c. At least once per 24 hours, when the Reactor Coolant System is drained below the hot leg centerline, by consideration of the factors in 4.1.1.2b. and by verifying at least two charging pumps are rendered inoperable by racking out their motor circuit breakers.

BORON DILUTION

LIMITING CONDITION FOR OPERATION

3.1.1.3 The flow rate of reactor coolant to the reactor pressure vessel shall be ≥ 3000 gpm whenever a reduction in Reactor Coolant System boron concentration is being made.

APPLICABILITY: ALL MODES.

ACTION:

With the flow rate of reactor coolant to the reactor pressure vessel < 3000 gpm, immediately suspend all operations involving a reduction in boron concentration of the Reactor Coolant System.

SURVEILLANCE REQUIREMENTS

4.1.1.3 The flow rate of reactor coolant to the reactor pressure vessel shall be determined to be ≥ 3000 gpm within 1 hour prior to the start of and at least once per hour during a reduction in the Reactor Coolant System boron concentration by either:

a. Verifying at least one reactor coolant pump is in operation, or

b. Verifying that at least one low pressure safety injection pump is in operation and supplying ≥ 3000 gpm to the reactor pressure vessel.

3/4.1.2 BORATION SYSTEMS

FLOW PATHS - SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.1.2.1 As a minimum, one of the following boron injection flow paths and one associated heat tracing circuit shall be OPERABLE and capable of being powered from an OPERABLE emergency power source:

a. A flow path from the boric acid makeup tank via either a boric acid makeup pump or a gravity feed connection and charging pump to the Reactor Coolant System if only the boric acid makeup tank in Specification 3.1.2.7a. is OPERABLE, or

b. The flow path from the refueling water tank via either a charging pump or a high pressure safety injection pump to the Reactor Coolant System if only the refueling water tank in Specification 3.1.2.7b. is OPERABLE.

APPLICABILITY: MODES 5 and 6.

ACTION:

With none of the above flow paths OPERABLE or capable of being powered from an OPERABLE emergency power source, suspend all operations involving CORE ALTERATIONS or positive reactivity changes.

SURVEILLANCE REQUIREMENTS

4.1.2.1 At least one of the above required flow paths shall be demonstrated OPERABLE:

a. At least once per 7 days by verifying that the temperature of the heat traced portion of the flow path is above the temperature limit line shown on Figure 3.1-1 when a flow path from the boric acid makeup tanks is used.

b. At least once per 31 days by verifying that each valve (manual, power-operated, or automatic) in the flow path that is not locked, sealed, or otherwise secured in position, is in its correct position.

FLOW PATHS - OPERATING

LIMITING CONDITION FOR OPERATION

3.1.2.2 At least two of the following three boron injection flow paths and one associated heat tracing circuit shall be OPERABLE:

a. Two flow paths from the boric acid makeup tanks via either a boric acid makeup pump or a gravity feed connection, and a charging pump to the Reactor Coolant System, and

b. The flow path from the refueling water tank via a charging pump to the Reactor Coolant System.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

With only one of the above required boron injection flow paths to the Reactor Coolant System OPERABLE, restore at least two boron injection flow paths to the Reactor Coolant System to OPERABLE status within 72 hours or be in at least HOT STANDBY and borated to a SHUTDOWN MARGIN equivalent to at least 3.0% delta k/k at 200°F within the next 6 hours; restore at least two flow paths to OPERABLE status within the next 7 days or be in COLD SHUTDOWN within the next 30 hours.

SURVEILLANCE REQUIREMENTS

4.1.2.2 At least two of the above required flow paths shall be demonstrated OPERABLE:

a. At least once per 7 days by verifying that the temperature of the heat traced portion of the flow path from the boric acid makeup tanks is above the temperature limit line shown on Figure 3.1-1.

b. At least once per 31 days by verifying that each valve (manual, power-operated or automatic) in the flow path that is not locked, sealed, or otherwise secured in position, is in its correct position.

c. At least once per 18 months during shutdown by verifying that each automatic valve in the flow path actuates to its correct position on an SIAS test signal.

d. At least once per 18 months by verifying that the flow path required by Specification 3.1.2.2a delivers at least 40 gpm to the Reactor Coolant System.

CHARGING PUMPS - SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.1.2.3 At least one charging pump or one high pressure safety injection pump in the boron injection flow path required OPERABLE pursuant to Specification 3.1.2.1 shall be OPERABLE and capable of being powered from an OPERABLE emergency power source.

APPLICABILITY: MODES 5 and 6.

ACTION:

With no charging pump or high pressure safety injection pump OPERABLE or capable of being powered from an OPERABLE emergency power source, suspend all operations involving CORE ALTERATIONS or positive reactivity changes.

SURVEILLANCE REQUIREMENTS

4.1.2.3 At least the above required pump shall be demonstrated OPERABLE by verifying the charging pump develops a flow rate of greater than or equal to 40 gpm or the high pressure safety injection pump develops a total head of greater than or equal to 2854 ft when tested pursuant to Specification 4.0.5.

REACTIVITY CONTROL SYSTEMS

CHARGING PUMPS - OPERATING

LIMITING CONDITION FOR OPERATION

3.1.2.4 At least two charging pumps shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

With only one charging pump OPERABLE, restore at least two charging pumps to OPERABLE status within 72 hours or be in at least HOT STANDBY and borated to a SHUTDOWN MARGIN equivalent to at least 3.0% delta k/k at 200°F within the next 6 hours; restore at least two charging pumps to OPERABLE status within the next 7 days or be in COLD SHUTDOWN within the next 30 hours.

SURVEILLANCE REQUIREMENTS

4.1.2.4.1 At least two charging pumps shall be demonstrated OPERABLE by verifying that each pump develops a flow rate of greater than or equal to 40 gpm when tested pursuant to Specification 4.0.5.

4.1.2.4.2 At least once per 18 months verify that each charging pump starts automatically on an SIAS test signal.

BORIC ACID MAKEUP PUMPS - SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.1.2.5 At least one boric acid makeup pump shall be OPERABLE and capable of being powered from an OPERABLE emergency bus if only the flow path through the boric acid pump in Specification 3.1.2.1a. is OPERABLE.

APPLICABILITY: MODES 5 and 6.

ACTION:

With no boric acid makeup pump OPERABLE as required to complete the flow path of Specification 3.1.2.1a., suspend all operations involving CORE ALTERATIONS or positive reactivity changes.

SURVEILLANCE REQUIREMENTS

4.1.2.5 The above required boric acid makeup pump shall be demonstrated OPERABLE by verifying, that on recirculation flow, the pump develops a discharge pressure of greater than or equal to 90 psig when tested pursuant to Specification 4.0.5.

BORIC ACID MAKEUP PUMPS - OPERATING

LIMITING CONDITION FOR OPERATION

3.1.2.6 At least the boric acid makeup pump(s) in the boron injection flow path(s) required OPERABLE pursuant to Specification 3.1.2.2a shall be OPERABLE and capable of being powered from an OPERABLE emergency bus if the flow path through the boric acid pump(s) in Specification 3.1.2.2a is OPERABLE.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

With one boric acid makeup pump required for the boron injection flow path(s) pursuant to Specification 3.1.2.2a inoperable, restore the boric acid makeup pump to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and borated to a SHUTDOWN MARGIN equivalent to at least 3.0% delta k/k at 200°F; restore the above required boric acid makeup pump(s) to OPERABLE status within the next 7 days or be in COLD SHUTDOWN within the next 30 hours.

SURVEILLANCE REQUIREMENTS

4.1.2.6 The above required boric acid makeup pump(s) shall be demonstrated OPERABLE by verifying, that on recirculation flow, the pump(s) develop a discharge pressure of greater than or equal to 90 psig when tested pursuant to Specification 4.0.5.

BORATED WATER SOURCES - SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.1.2.7 As a minimum, one of the following borated water sources shall be OPERABLE:

a. One boric acid makeup tank and at least one associated heat tracing circuit with a minimum contained volume of 4150 gallons of 8 weight percent boron.

b. The refueling water tank with:

1. A minimum contained borated water volume of 125,000 gallons,

2. A minimum boron concentration of 1720 ppm, and

3. A solution temperature between 40°F and 120°F.

APPLICABILITY: MODES 5 and 6.

ACTION:

With no borated water sources OPERABLE, suspend all operations involving CORE ALTERATIONS or positive reactivity changes.

SURVEILLANCE REQUIREMENTS

4.1.2.7 The above required borated water source shall be demonstrated OPERABLE:

a. At least once per 7 days by:

1. Verifying the boron concentration of the water,

2. Verifying the contained borated water volume of the tank, and

3. Verifying the boric acid makeup tank solution temperature when it is the source of borated water.

b. At least once per 24 hours by verifying the RWT temperature when it is the source of borated water and the outside air temperature is outside the range of 40°F and 120°F.

BORATED WATER SOURCES - OPERATING

LIMITING CONDITION FOR OPERATION

3.1.2.8 Each of the following borated water sources shall be OPERABLE:

a. At least one boric acid makeup tank and at least one associated heat tracing circuit per tank with the contents of the tank in accordance with Figure 3.1-1, and

b. The refueling water tank with:

1. A minimum contained borated water volume of 417,100 gallons,
2. A boron concentration of between 1720 and 2100 ppm of boron, and
3. A solution temperature between 55°F and 100°F.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

a. With the above required boric acid makeup tank inoperable, restore the tank to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and borated to a SHUTDOWN MARGIN equivalent to at least 3.0% delta k/k at 200°F; restore the above required boric acid makeup tank to OPERABLE status within the next 7 days or be in COLD SHUTDOWN within the next 30 hours.

b. With the refueling water tank inoperable, restore the tank to OPERABLE status within 1 hour or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.1.2.8 Each borated water source shall be demonstrated OPERABLE:

a. At least once per 7 days by:

1. Verifying the boron concentration in the water,
2. Verifying the contained borated water volume of the water source, and
3. Verifying the boric acid makeup tank solution temperature.

b. At least once per 24 hours by verifying the RWT temperature when the outside air temperature is outside the range of 55°F and 100°F.

TABLE 3.1-1

MONITORING FREQUENCIES FOR BACKUP BORON DILUTION DETECTION FOR ST. LUCIE-2

MODE	Number of OPERABLE Charging Pumps* 0	1	2	3
3	12 hr	100 min	40 min	25 min
4	12 hr	130 min	50 min	30 min
5	8 hr	100 min	40 min	25 min
5 (RCS level below hot leg centerline)	8 hr	35 min	Operation not allowed**	Operation not allowed**
6	24 hr	220 min	95 min	55 min

*Charging pump OPERABILITY for any period of time shall constitute OPERABILITY for the entire monitoring frequency.

**In MODE 5 with the RCS level below the hot leg centerline, at least two charging pumps shall be verified to be inoperable by racking out their motor circuit breakers.

3/4.1.3 MOVABLE CONTROL ASSEMBLIES

CEA POSITION

LIMITING CONDITION FOR OPERATION

3.1.3.1 The CEA Block Circuit and all full-length (shutdown and regulating) CEAs which are inserted in the core, shall be OPERABLE with each CEA of a given group positioned within 7.0 inches (indicated position) of all other CEAs in its group.

APPLICABILITY: MODES 1* and 2*.

ACTION:

a. With one or more full-length CEAs inoperable due to being immovable as a result of excessive friction or mechanical interference or known to be untrippable, determine that the SHUTDOWN MARGIN requirement of Specification 3.1.1.1 is satisfied within 1 hour and be in at least HOT STANDBY within 6 hours.

b. With the CEA Block Circuit inoperable, within 6 hours either:

   1. With one CEA position indicator per group inoperable take action per Specification 3.1.3.2, or

   2. With the group overlap and/or sequencing interlocks inoperable maintain CEA groups 1, 2, 3 and 4 fully withdrawn and the CEAs in group 5 to less than 15% insertion and place and maintain CEA drive system in either the "Manual" or "Off" position, or

   3. Be in at least HOT STANDBY.

c. With more than one full-length CEA inoperable or misaligned from any other CEA in its group by more than 15 inches (indicated position), be in at least HOT STANDBY within 6 hours.

d. With one full-length CEA misaligned from any other CEA in its group by more than 15 inches, operation in MODES 1 and 2 may continue, provided that the misaligned CEA is positioned within 15 inches of the other CEAs in its group in accordance with the time constraints shown in Figure 3.1-1a.

*See Special Test Exceptions 3.10.2, 3.10.4, and 3.10.5.

ACTION: (Continued)

e. With one full-length CEA misaligned from any other CEA in its group by more than 15 inches beyond the time constraints shown in Figure 3.1-1a, reduce power to $\leq$ 70% of RATED THERMAL POWER prior to completing ACTION e.1 or e.2.

 1. Restore the CEA to OPERABLE status within its specified alignment requirements, or

 2. Declare the CEA inoperable and satisfy SHUTDOWN MARGIN requirement of Specification 3.1.1.1. After declaring the CEA inoperable, operation in MODES 1 and 2 may continue pursuant to the requirements of Specification 3.1.3.6 provided:*

  a) Within 1 hour the remainder of the CEAs in the group with the inoperable CEA shall be aligned to within 7.0 inches of the inoperable CEA while maintaining the allowable CEA sequence and insertion limits shown on Figure 3.1-2; the THERMAL POWER level shall be restricted pursuant to Specification 3.1.3.6 during subsequent operation.

  b) The SHUTDOWN MARGIN requirement of Specification 3.1.1.1 is determined at least once per 12 hours.

f. With one or more full-length CEA(s) misaligned from any other CEAs in its group by more than 7.0 inches but less than or equal to 15 inches, operation in MODES 1 and 2 may continue, provided that within 1 hour the misaligned CEA(s) is either:

 1. Restored to OPERABLE status within its above specified alignment requirements, or

 2. Declared inoperable and the SHUTDOWN MARGIN requirement of Specification 3.1.1.1 is satisfied. After declaring the CEA inoperable, operation in MODES 1 and 2 may continue pursuant to the requirements of Specification 3.1.3.6 provided:

  a) Within 1 hour the remainder of the CEAs in the group with the inoperable CEA shall be aligned to within 7.0 inches of the inoperable CEA while maintaining the allowable CEA sequence and insertion limits shown on Figure 3.1-2; the THERMAL POWER level shall be restricted pursuant to Specification 3.1.3.6 during subsequent operation.

  b) The SHUTDOWN MARGIN requirement of Specification 3.1.1.1 is determined at least once per 12 hours.

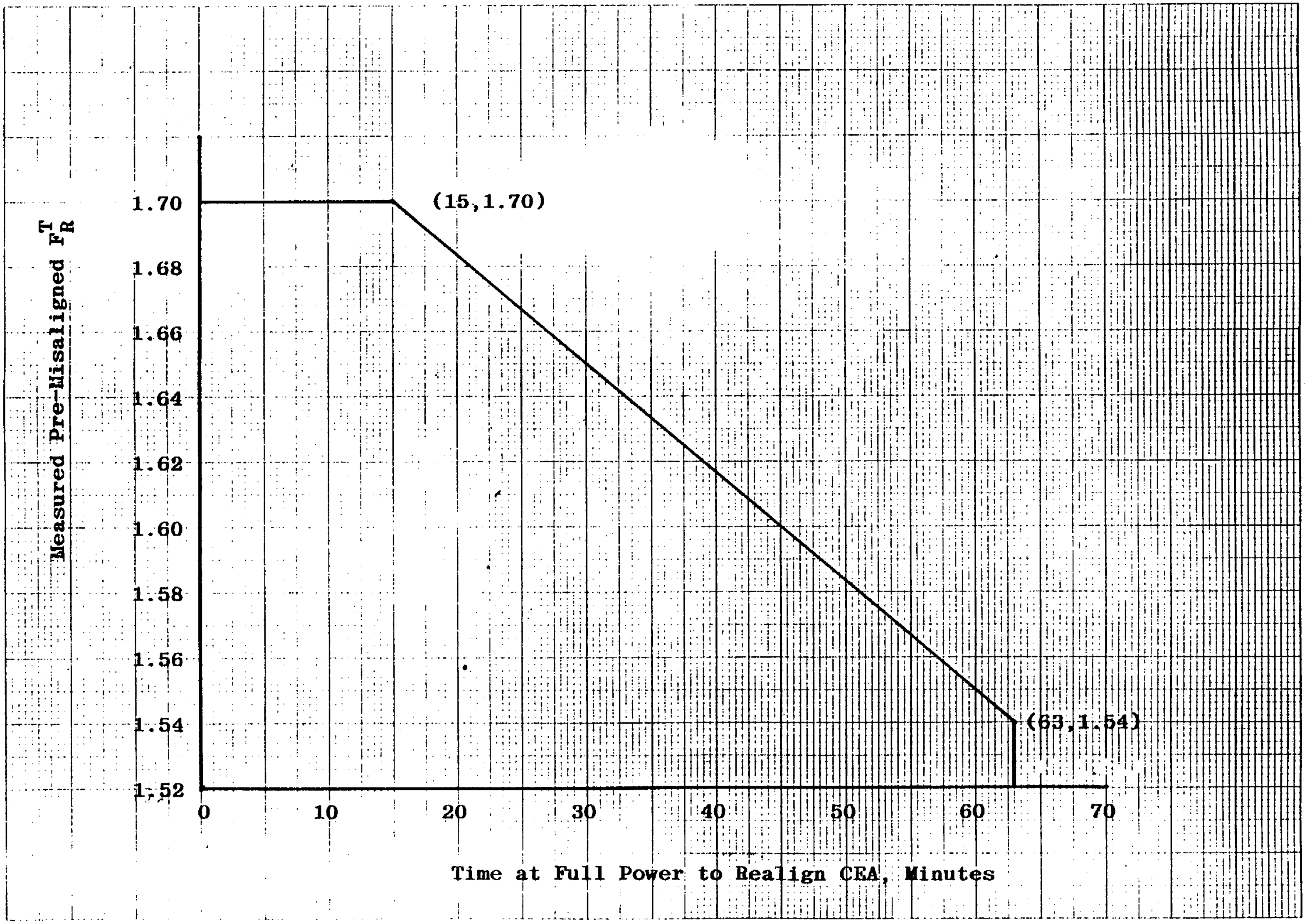
 Otherwise, be in at least HOT STANDBY within 6 hours.

g. With one full-length CEA inoperable due to causes other than addressed by ACTION a., above, and inserted beyond the Long Term Steady State Insertion Limits but within its above specified alignment requirements, operation in MODES 1 and 2 may continue pursuant to the requirements of Specification 3.1.3.6.

---

*If the pre-misalignment ASI was more negative than -0.15, reduce power to $\leq$70% of RATED THERMAL POWER or 70% of the THERMAL POWER level prior to the misalignment, whichever is less, prior to completing ACTION e.2.a) and e.2.b).

Figure 3.1-1a
Allowable Time to Realign CEA vs. Initial F_R^T



ACTION: (Continued)

h. With one full-length CEA inoperable due to causes other than addressed by ACTION a., above, but within its above specified alignment requirements and either fully withdrawn or within the Long Term Steady State Insertion Limits if in full-length CEA group 5, operation in MODES 1 and 2 may continue.

SURVEILLANCE REQUIREMENTS

4.1.3.1.1 The position of each full-length CEA shall be determined to be within 7.0 inches (indicated position) of all other CEAs in its group at least once per 12 hours except during time intervals when the Deviation Circuit and/or CEA Block Circuit are inoperable, then verify the individual CEA positions at least once per 4 hours.

4.1.3.1.2 Each full-length CEA not fully inserted in the core shall be determined to be OPERABLE by movement of at least 7.0 inches in any one direction at least once per 31 days.

4.1.3.1.3 The CEA Block Circuit shall be demonstrated OPERABLE at least once per 31 days by a functional test which verifies that the circuit prevents any CEA from being misaligned from all other CEAs in its group by more than 7.0 inches (indicated position).

4.1.3.1.4 The CEA Block Circuit shall be demonstrated OPERABLE by a functional test which verifies that the circuit maintains the CEA group overlap and sequencing requirements of Specification 3.1.3.6 and that the circuit prevents the regulating CEAs from being inserted beyond the Power Dependent Insertion Limit of Figure 3.1-2:

*a. Prior to each entry into MODE 2 from MODE 3, except that such verification need not be performed more often than once per 31 days, and

b. At least once per 6 months.

*The licensee shall be excepted from compliance during the initial startup test program for an entry into MODE 2 from MODE 3 made in association with a measurement of power defect.

POSITION INDICATOR CHANNELS - SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.1.3.3 At least one CEA position indicator channel shall be OPERABLE for each shutdown or regulating CEA not fully inserted.

APPLICABILITY: MODES 3*, 4,* and 5*.

ACTION:

With less than the above required position indicator channel(s) OPERABLE, immediately open the reactor trip breakers.

SURVEILLANCE REQUIREMENTS

4.1.3.3 Each of the above required CEA position indicator channel(s) shall be determined to be OPERABLE by performance of a CHANNEL FUNCTIONAL TEST at least once per 18 months.

*With the reactor trip breakers in the closed position.

CEA DROP TIME

LIMITING CONDITION FOR OPERATION

3.1.3.4 The individual full-length (shutdown and regulating) CEA drop time, from a fully withdrawn position, shall be less than or equal to 2.7 seconds from when the electrical power is interrupted to the CEA drive mechanism until the CEA reaches its 90% insertion position with:

a. T_{avg} greater than or equal to 515°F, and

b. All reactor coolant pumps operating.

APPLICABILITY: MODES 1 and 2.

ACTION:

a. With the drop time of any full-length CEA determined to exceed the above limit:

1. If in MODE 1 or 2, be in at least HOT STANDBY within 6 hours, or

2. If in MODE 3, 4, or 5, restore the CEA drop time to within the above limit prior to proceeding to MODE 1 or 2.

b. With the CEA drop times within limits but determined at less than full reactor coolant flow, operation may proceed provided THERMAL POWER is restricted to less than or equal to the maximum THERMAL POWER level allowable for the reactor coolant pump combination operating at the time of CEA drop time determination.

SURVEILLANCE REQUIREMENTS

4.1.3.4 The CEA drop time of full-length CEAs shall be demonstrated through measurement prior to reactor criticality:

a. For all CEAs following each removal and installation of the reactor vessel head,

b. For specifically affected individuals CEAs following any maintenance on or modification to the CEA drive system which could affect the drop time of those specific CEAs, and

c. At least once per 18 months:

ACTION: (Continued)

c. With the regulating CEA groups inserted between the Long Term Steady State Insertion Limits and the Power Dependent Insertion Limits for intervals greater than 5 EFPD per 30 EFPD interval or greater than 14 EFPD per calendar year, either:

1. Restore the regulating groups to within the Long Term Steady State Insertion Limits within 2 hours, or

2. Be in at least HOT STANDBY within 6 hours.

SURVEILLANCE REQUIREMENTS

4.1.3.6 The position of each regulating CEA group shall be determined to be within the Power Dependent Insertion Limits at least once per 12 hours except during time intervals when the PDIL Auctioneer Alarm Circuit is inoperable, then verify the individual CEA positions at least once per 4 hours. The accumulated times during which the regulating CEA groups are inserted beyond the Long Term Steady State Insertion Limits but within the Power Dependent Insertion Limits shall be determined at least once per 24 hours.

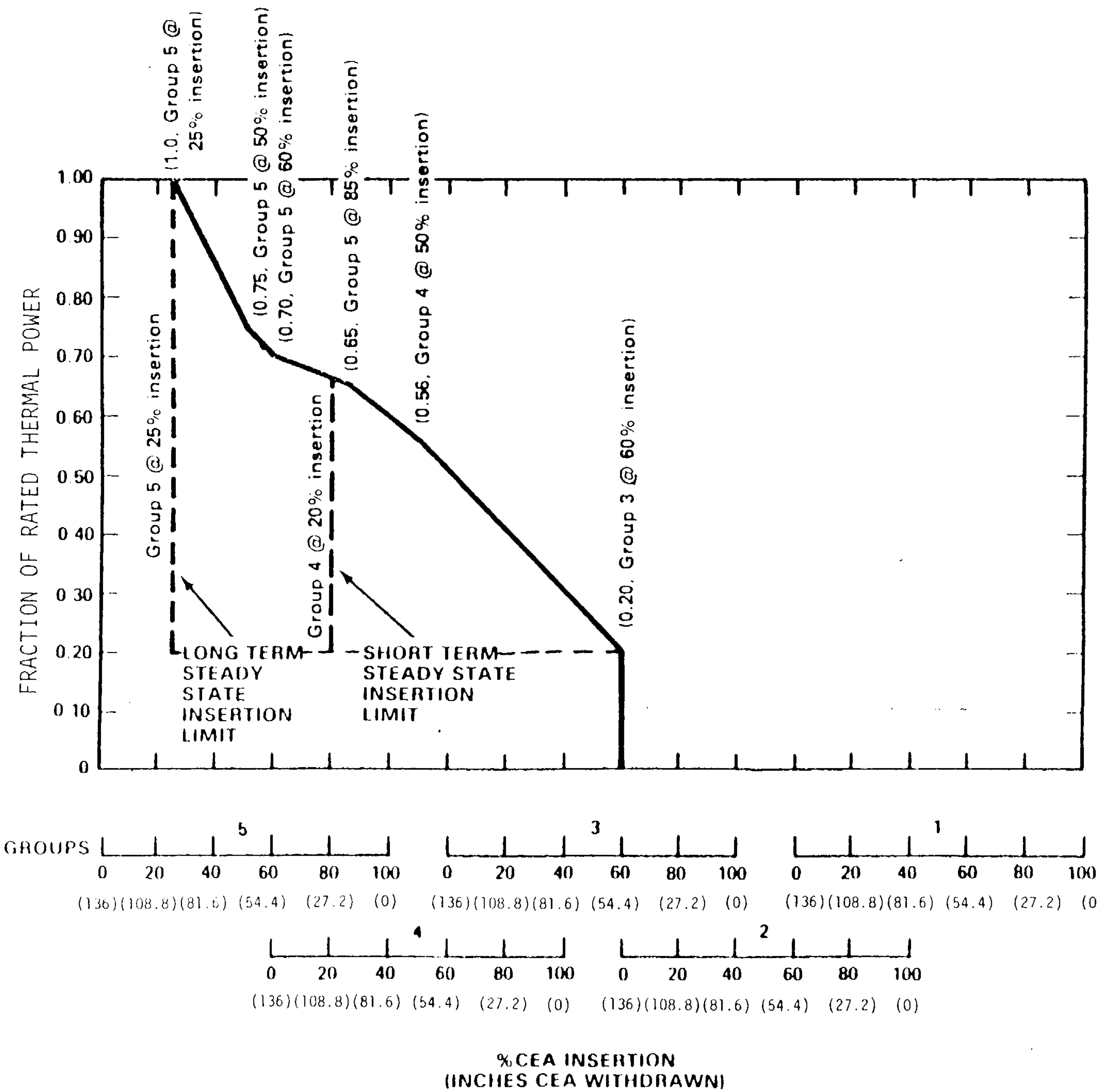


Figure 3.1-2

CEA Insertion Limits vs. THERMAL POWER with Four Reactor Coolant Pumps Operating

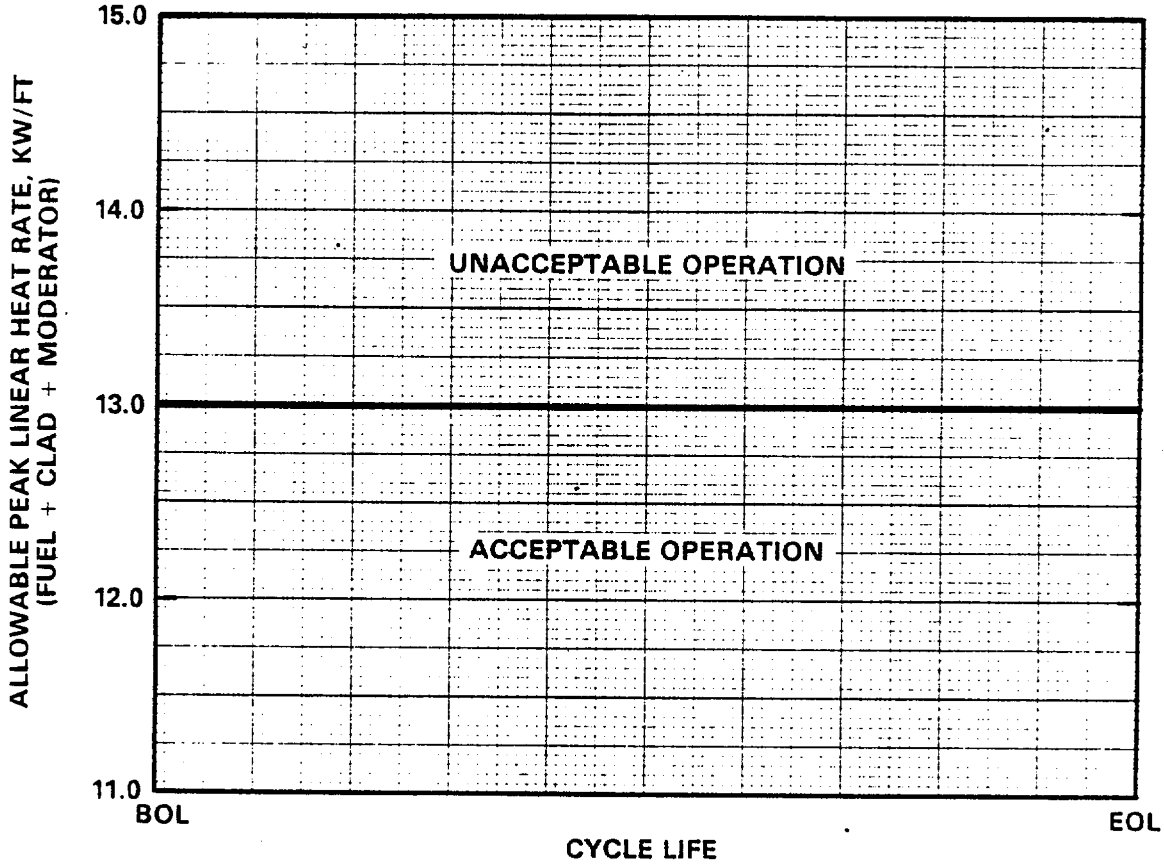


Figure 3.2-1
Allowable peak linear heat rate vs burnup

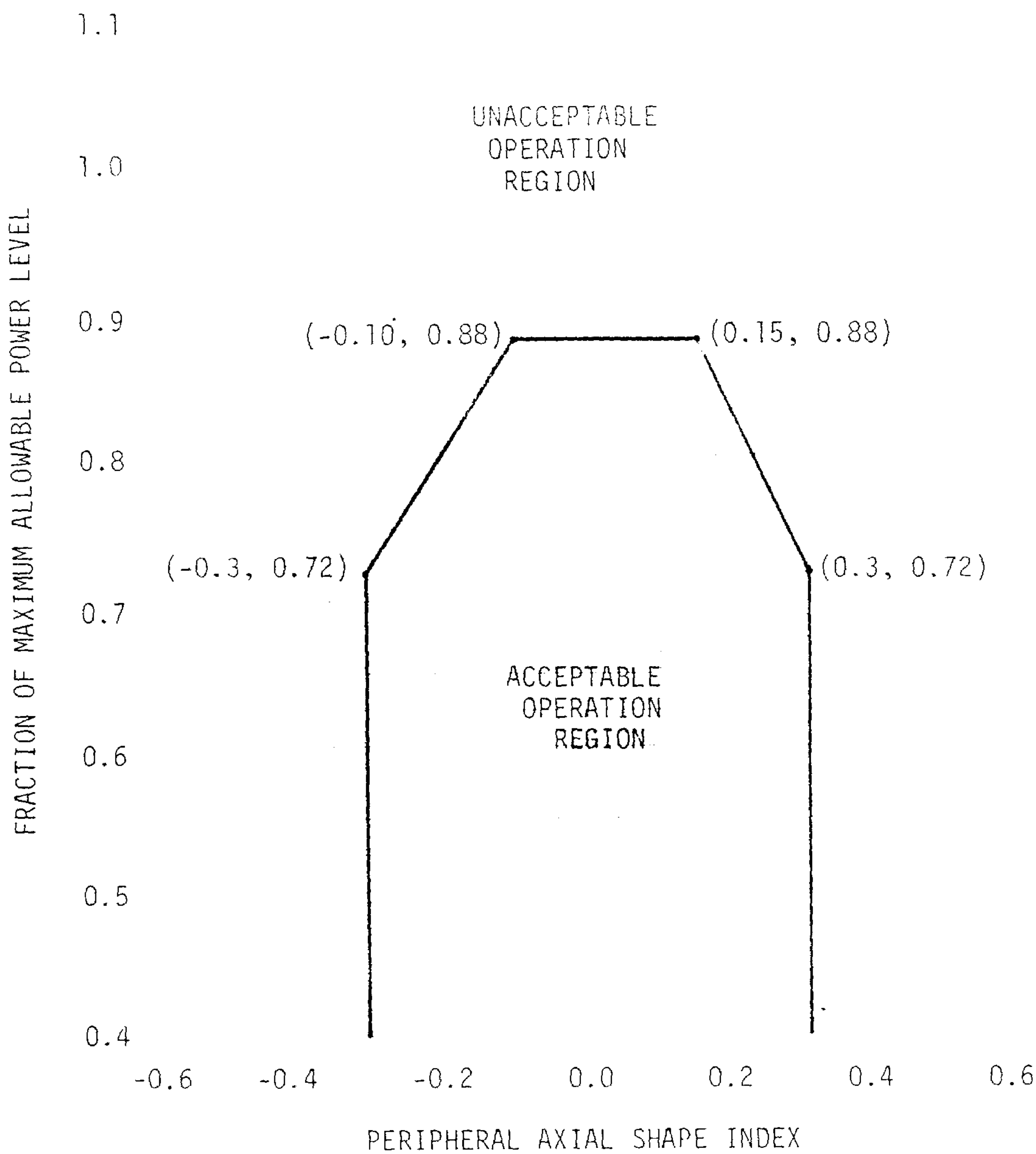
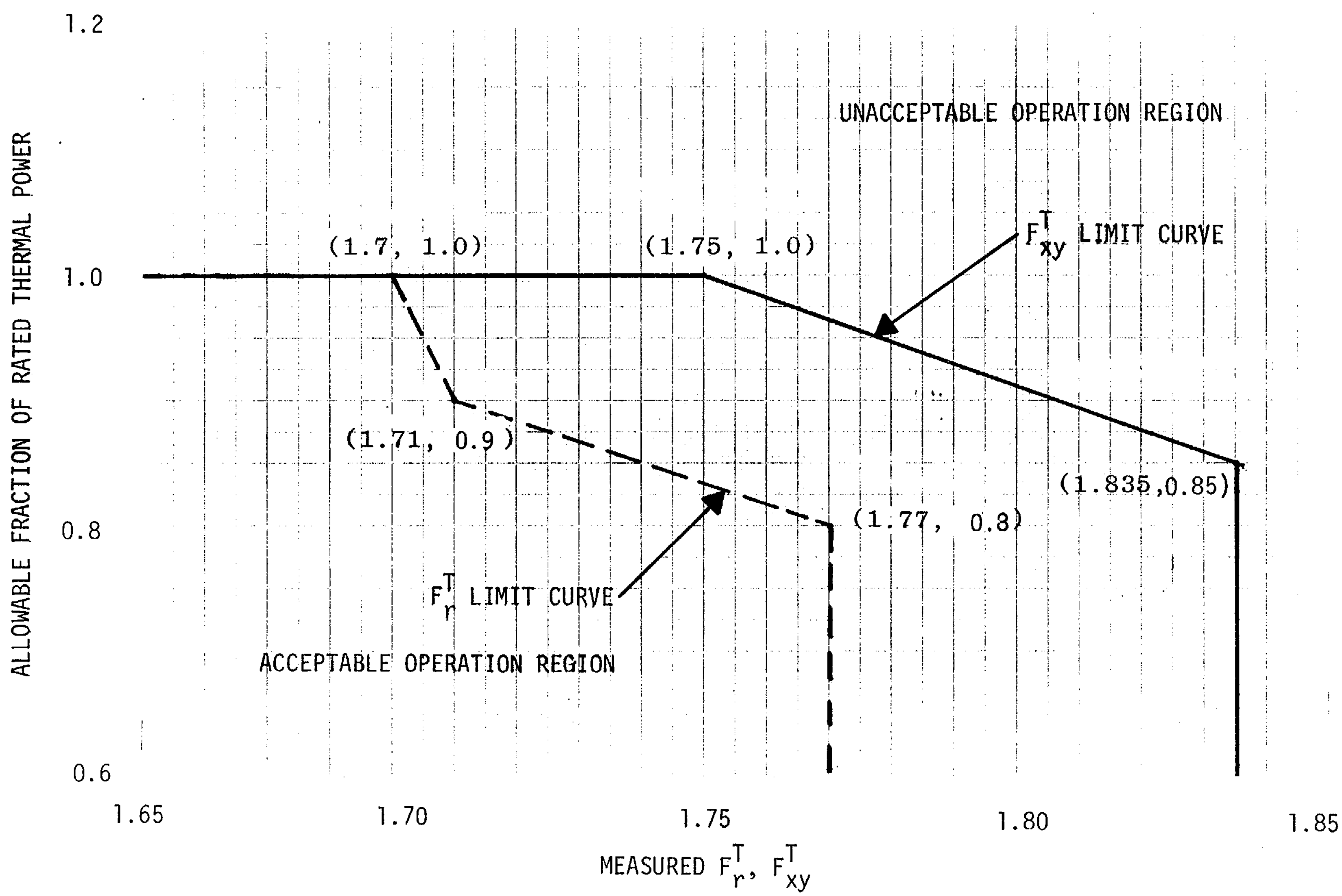


FIGURE 3.2-2

AXIAL SHAPE INDEX VS FRACTION OF MAXIMUM ALLOWABLE POWER LEVEL PER SPECIFICATION 4.2.1.3

FIGURE 3.2-3

ALLOWABLE COMBINATIONS OF THERMAL POWER AND F_r^T, F_{xy}^T



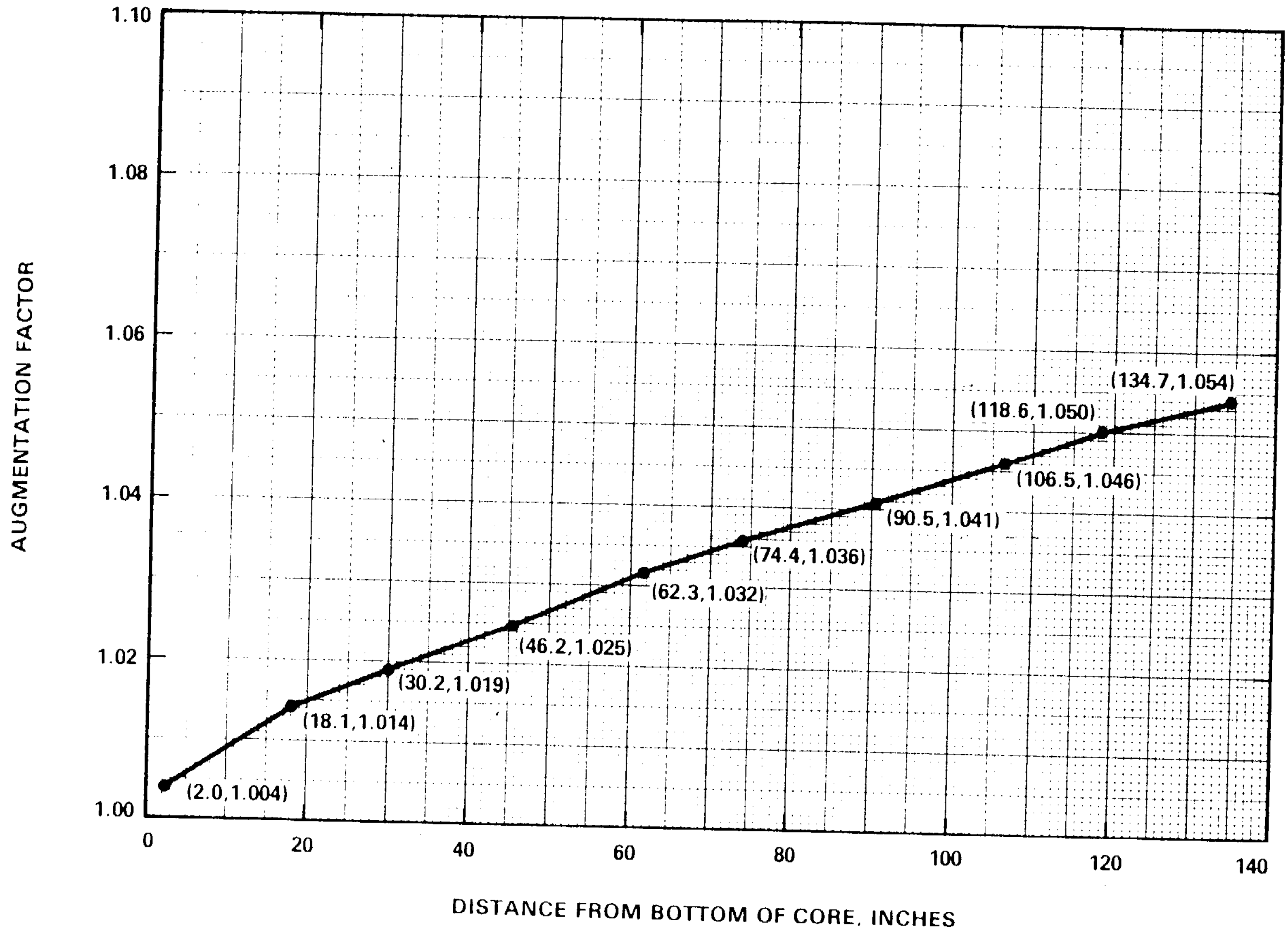


Figure 4.2-1
Augmentation factors vs distance from bottom of core

3/4.2.2 TOTAL PLANAR RADIAL PEAKING FACTORS - F^T_{xy}

LIMITING CONDITION FOR OPERATION

3.2.2 The calculated value of F^T_{xy} shall be limited to ≤ 1.75.

APPLICABILITY: MODE 1*.

ACTION:

With $F^T_{xy} > 1.75$, within 6 hours either:

a. Reduce THERMAL POWER to bring the combination of THERMAL POWER and F^T_{xy} to within the limits of Figure 3.2-3 and withdraw the full length CEAs to or beyond the Long Term Steady State Insertion Limits of Specification 3.1.3.6; or

b. Be in HOT STANDBY.

SURVEILLANCE REQUIREMENTS

4.2.2.1 The provisions of Specification 4.0.4 are not applicable.

4.2.2.2 F^T_{xy} shall be calculated by the expression $F^T_{xy} = F_{xy}(1+T_q)$ when F_{xy} is calculated with a non-full core power distribution analysis code and shall be calculated as $F^T_{xy} = F_{xy}$ when calculations are performed with a full core power distribution analysis code. F^T_{xy} shall be determined to be within its limit at the following intervals:

a. Prior to operation above 70% of RATED THERMAL POWER after each fuel loading,

b. At least once per 31 days of accumulated operation in MODE 1, and

c. Within 4 hours if the AZIMUTHAL POWER TILT (T_q) is > 0.03.

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*See Special Test Exception 3.10.2.

SURVEILLANCE REQUIREMENTS (Continued)

4.2.2.3 F_{xy} shall be determined each time a calculation of F^T_{xy} is required by using the incore detectors to obtain a power distribution map with all full length CEAs at or above the Long Term Steady State Insertion Limit for the existing reactor coolant pump combination. This determination shall be limited to core planes between 15% and 85% of full core height and shall exclude regions influenced by grid effects.

4.2.2.4 T_q shall be determined each time a calculation of F^T_{xy} is made using a non full core power distribution analysis code. The value of T_q used in this case to determine F^T_{xy} shall be the measured value of T_q.

TOTAL INTEGRATED RADIAL PEAKING FACTOR - F_r^T

LIMITING CONDITION FOR OPERATION

3.2.3 The calculated value of F_r^T, shall be limited to $\leq$ 1.70.

APPLICABILITY: MODE 1*.

ACTION:

With $F_r^T > 1.70$, within 6 hours either:

a. Be in at least HOT STANDBY, or

b. Reduce THERMAL POWER to bring the combination of THERMAL POWER and F_r^T to within the limits of Figure 3.2-3 and withdraw the full-length CEAs to or beyond the Long Term Steady State Insertion Limits of Specification 3.1.3.6. The THERMAL POWER limit determined from Figure 3.2-3 shall then be used to establish a revised upper THERMAL POWER level limit on Figure 3.2-4 (truncate Figure 3.2-4 at the allowable fraction of RATED THERMAL POWER determined by Figure 3.2-3) and subsequent operation shall be maintained within the reduced acceptable operation region of Figure 3.2-4.

SURVEILLANCE REQUIREMENTS

4.2.3.1 The provisions of Specification 4.0.4 are not applicable.

4.2.3.2 F_r^T shall be calculated by the expression $F_r^T = F_r(1+T_q)$ when F_r is calculated with a non-full core power distribution analysis code and shall be calculated as $F_r^T = F_r$ when calculations are performed with a full core power distribution analysis code. F_r^T shall be determined to be within its limit at the following intervals:

a. Prior to operation above 70% of RATED THERMAL POWER after each fuel loading.

b. At least once per 31 days of accumulated operation in MODE 1, and

c. Within 4 hours if the AZIMUTHAL POWER TILT (T_q) is > 0.03.

*See Special Test Exception 3.10.2.

SURVEILLANCE REQUIREMENTS (Continued)

4.2.3.3 F_r shall be determined each time a calculation of F_r^T is required by using the incore detectors to obtain a power distribution map with all full length CEAs at or above the Long Term Steady State Insertion Limit for the existing reactor coolant pump combination.

4.2.3.4 T_q shall be determined each time a calculation of F_r^T is made using a non-full core power distribution analysis code. The value of T_q used to determine F_r^T in this case shall be the measured value of T_q.

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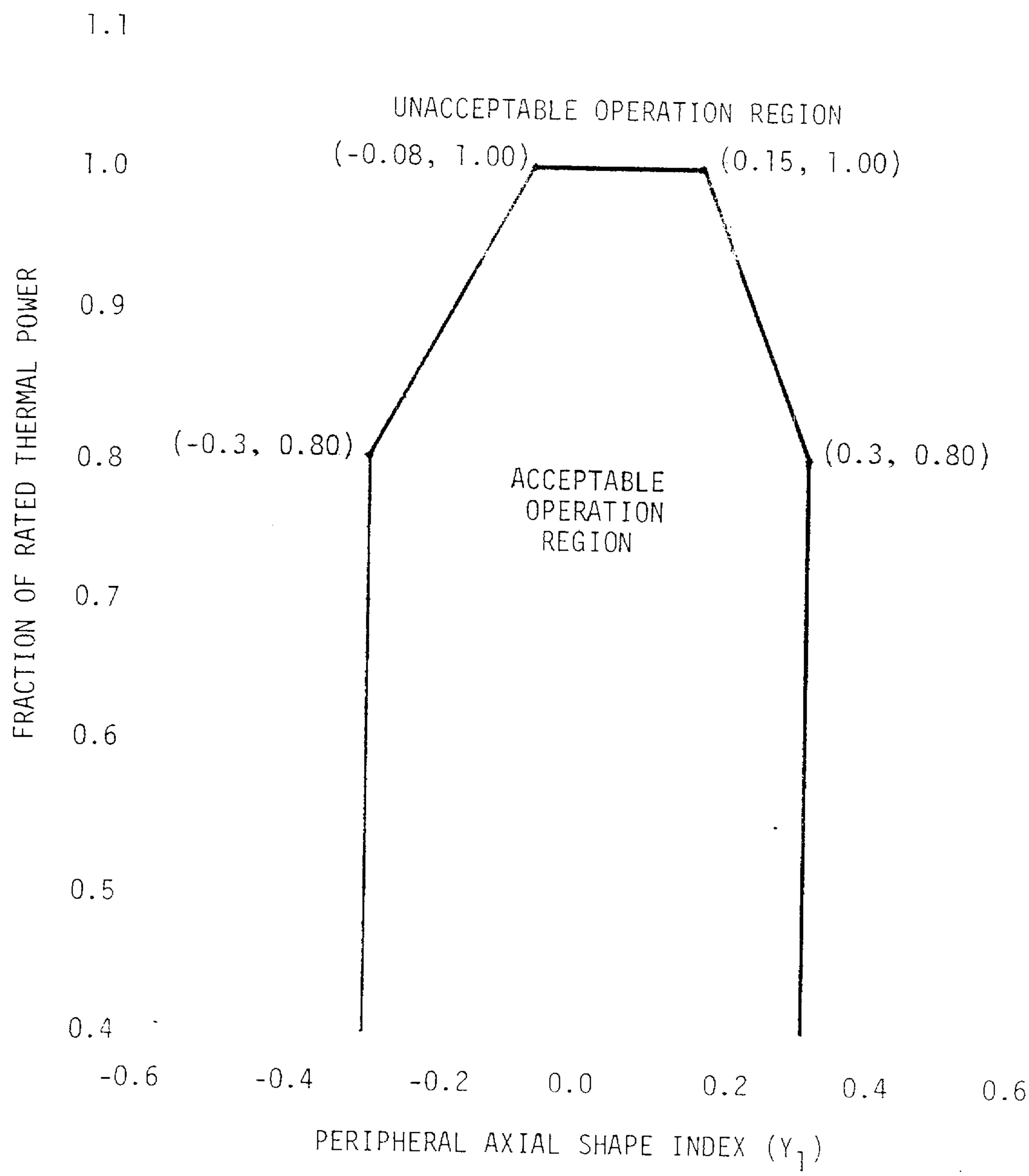

FIGURE 3.2-4

AXIAL SHAPE INDEX OPERATING LIMITS WITH
FOUR REACTOR COOLANT PUMPS OPERATING

TABLE 3.2-2

DNB MARGIN

LIMITS

PARAMETER	FOUR REACTOR COOLANT PUMPS OPERATING
Cold Leg Temperature (Narrow Range)	535°F* $\leq$ T $\leq$ 549°F
Pressurizer Pressure	2225 psia** $\leq$ P_{PZR} $\leq$ 2350 psia*
Reactor Coolant Flow Rate	$\geq$ 363,000 gpm
AXIAL SHAPE INDEX	Figure 3.2-4

*Applicable only if power level $\geq$ 70% RATED THERMAL POWER.

**Limit not applicable during either a THERMAL POWER ramp increase in excess of 5% of RATED THERMAL POWER or a THERMAL POWER step increase of greater than 10% of RATED THERMAL POWER.

ACTION STATEMENTS

ACTION 2 (Continued)

6.	Cold Leg Temperature	Variable Power Level - High (RPS) Thermal Margin/Low Pressure (RPS) Local Power Density - High (RPS)
7.	Hot Leg Temperature	Variable Power Level - High (RPS) Thermal Margin/Low Pressure (RPS) Local Power Density - High (RPS)

ACTION 3 - With the number of channels OPERABLE one less than required by the Minimum Channels OPERABLE requirement, suspend all operations involving positive reactivity changes. Verify compliance with the SHUTDOWN MARGIN requirements of Specification 3.1.1.1 or 3.1.1.2, as applicable, within 1 hour and at least once per 12 hours thereafter.

ACTION 4 - With the number of channels OPERABLE one less than required by the Minimum Channels OPERABLE requirement, STARTUP and/or POWER OPERATION may continue provided the reactor trip breakers of the inoperable channel are placed in the tripped condition within 1 hour, otherwise, be in at least HOT STANDBY within 6 hours; however, one channel may be bypassed for up to 1 hour, provided the trip breakers of any inoperable channel are in the tripped condition, for surveillance testing per Specification 4.3.1.1.

ACTION 5 - With the number of OPERABLE channels one less than the Minimum Channels OPERABLE requirement restore the inoperable channel to OPERABLE status within 48 hours or open the reactor trip breakers within the next hour.

TABLE 3.3-2

REACTOR PROTECTIVE INSTRUMENTATION RESPONSE TIMES

FUNCTIONAL UNIT	RESPONSE TIME
1. Manual Reactor Trip	Not Applicable
2. Variable Power Level - High	$\leq$ 0.40 second*,**
3. Pressurizer Pressure - High	$\leq$ 1.15 seconds
4. Thermal Margin/Low Pressure	$\leq$ 0.90 second**
5. Containment Pressure - High	$\leq$ 1.15 seconds
6. Steam Generator Pressure - Low	$\leq$ 1.15 seconds
7. Steam Generator Pressure Difference - High	$\leq$ 1.15 seconds
8. Steam Generator Level - Low	$\leq$ 1.15 seconds
9. Local Power Density - High	$\leq$ 0.40 second*,**

TABLE 3.3-4

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION TRIP VALUES

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
1. SAFETY INJECTION (SIAS)		
a. Manual (Trip Buttons)	Not Applicable	Not Applicable
b. Containment Pressure - High	$\leq$ 3.5 psig	$\leq$ 3.6 psig
c. Pressurizer Pressure - Low	$\geq$ 1736 psia	$\geq$ 1728 psia
d. Automatic Actuation Logic	Not Applicable	Not Applicable
2. CONTAINMENT SPRAY (CSAS)		
a. Manual (Trip Buttons)	Not Applicable	Not Applicable
b. Containment Pressure -- High-High	$\leq$ 5.40 psig	$\leq$ 5.50 psig
c. Automatic Actuation Logic	Not Applicable	Not Applicable
3. CONTAINMENT ISOLATION (CIAS)		
a. Manual CIAS (Trip Buttons)	Not Applicable	Not Applicable
b. Safety Injection (SIAS)	Not Applicable	Not Applicable
c. Containment Pressure - High	$\leq$ 3.5 psig	$\leq$ 3.6 psig
d. Containment Radiation - High	$\leq$ 10 R/hr	$\leq$ 10 R/hr
e. Automatic Actuation Logic	Not Applicable	Not Applicable
4. MAIN STEAM LINE ISOLATION		
a. Manual (Trip Buttons)	Not Applicable	Not Applicable
b. Steam Generator Pressure - Low	$\geq$ 600 psia	$\geq$ 567 psia
c. Containment Pressure - High	$\leq$ 3.5 psig	$\leq$ 3.6 psig
d. Automatic Actuation Logic	Not Applicable	Not Applicable

TABLE 3.3-4 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION TRIP VALUES

FUNCTIONAL UNIT	TRIP VALUE	ALLOWABLE VALUES
5. CONTAINMENT SUMP RECIRCULATION (RAS)		
a. Manual RAS (Trip Buttons)	Not Applicable	Not Applicable
b. Refueling Water Storage Tank - Low	5.67 feet above tank bottom	4.62 feet to 6.24 feet above tank bottom
c. Automatic Actuation Logic	Not Applicable	Not Applicable
6. LOSS OF POWER		
a. (1) 4.16 kV Emergency Bus Undervoltage (Loss of Voltage)	$\geq$ 3120 volts	$\geq$ 3120 volts
(2) 480 V Emergency Bus Undervoltage (Loss of Voltage)	$\geq$ 360 volts	$\geq$ 360 volts
b. (1) 4.16 kV Emergency Bus Undervoltage (Degraded Voltage)	$\geq$ 3848 volts with a 10-second time delay	$\geq$ 3848 volts with a 10-second time delay
(2) 480 V Emergency Bus Undervoltage (Degraded Voltage)	$\geq$ 432 volts	$\geq$ 432 volts
7. AUXILIARY FEEDWATER (AFAS)		
a. Manual (Trip Buttons)	Not Applicable	Not Applicable
b. Automatic Actuation Logic	Not Applicable	Not Applicable
c. Steam Generator ΔP-High	$\leq$ 180.0 psid	$\leq$ 187.5 psid
d. SG 2A&2B Level Low	$\geq$ 20.6%	$\geq$ 20.0%
e. Feedwater Header High ΔP	$\leq$ 100.0 psid	$\leq$ 107.5 psid

TABLE 3.3-5

ENGINEERED SAFETY FEATURES RESPONSE TIMES

INITIATING SIGNAL AND FUNCTION	RESPONSE TIME IN SECONDS
1. Manual	
a. SIAS	
Safety Injection (ECCS)	Not Applicable
Containment Isolation(1)	Not Applicable
Shield Building Ventilation System	Not Applicable
Containment Purge Valve Isolation	Not Applicable
Containment Fan Coolers	Not Applicable
b. CSAS	
Containment Spray	Not Applicable
Iodine Removal	Not Applicable
c. CIAS	
Containment Isolation(1)	Not Applicable
Shield Building Ventilation System	Not Applicable
Containment Purge Valve Isolation	Not Applicable
d. MSIS	
Main Steam Isolation	Not Applicable
Feedwater Isolation	Not Applicable
e. RAS	
Containment Sump Recirculation	Not Applicable
f. AFAS	
Auxiliary Feedwater Actuation	Not Applicable
Feedwater Isolation	Not Applicable

TABLE 3.3-5 (Continued)

ENGINEERED SAFETY FEATURES RESPONSE TIMES

INITIATING SIGNAL AND FUNCTION	RESPONSE TIME IN SECONDS
2. Pressurizer Pressure-Low	
a. Safety Injection (ECCS)	≤ 30.0*/20.0**
b. Containment Isolation(1)	≤ 21.75*/11.75**
c. Shield Building Ventilation System	≤ 26.0*/10.0**
d. Containment Fan Coolers	≤ 24.15*/11.15**
e. Charging Flow	≤ 330.00*/180.00**
3. Containment Pressure-High	
a. Safety Injection (ECCS)	≤ 30.0*/20.0**
b. Containment Isolation(1)	≤ 21.75*/11.75**
c. Shield Building Ventilation System	≤ 26.0*/10.0**
d. Containment Fan Coolers	≤ 24.15*/11.15**
e. Feedwater Isolation	≤ 5.15*/5.15**
f. Main Steam Isolation	≤ 6.75*/6.75**
4. Containment Pressure--High-High	
a. Containment Spray/Iodine Removal	≤ 25.65*/11.15**
5. Containment Radiation-High	
a. Containment Isolation(1)	≤ 26.75*/16.75**
b. Shield Buildirg Ventilation System	≤ 32.75*/16.75**
6. Steam Generator Pressure-Low	
a. Feedwater Isolation	≤ 5.15/5.15**
b. Main Steam Isolation	≤ 6.75/6.75**
7. Refueling Water Storage Tank-Low	
a. Containment Sump Recirculation	≤ 111.15*/101.15**
8. 4.16 kV Emergency Bus Undervoltage (Loss of Voltage)	
a. Loss of Power (4.16 kV)	≤ 14
b. Loss of Power (480 V)	≤ 14
9. 4.16 kV Emergency Bus Undervoltage (Degraded Voltage)	
a. Loss of Power (4.16 kV)	≤ 12
b. Loss of Power (480 V)	≤ 22

TABLE 3.3-5 (Continued)

ENGINEERED SAFETY FEATURES RESPONSE TIMES

INITIATING SIGNAL AND FUNCTION	RESPONSE TIME IN SECONDS
10. Steam Generator Level-Low	
a. Auxiliary Feedwater	$\leq$ 120*/120**
b. Feedwater Isolation	$\leq$ 5.15*/5.15**
11. Feedwater Header ΔP	
a. Auxiliary Feedwater	$\leq$ 120*/120**
b. Feedwater Isolation	$\leq$ 5.15*/5.15**
12. Steam Generator ΔP	
a. Auxiliary Feedwater	$\leq$ 120*/120**
b. Feedwater Isolation	$\leq$ 5.15*/5.15**

NOTE: Response time for Motor-Driven and Steam-Driven Auxiliary Feedwater Pumps on all AFAS signal starts $\leq$ 120.0

TABLE NOTATION

*Diesel generator starting and sequence loading delays included. Response time limit includes movement of valves and attainment of pump or blower discharge pressure.

**Diesel generator starting and sequence loading delays not included. Offsite power available. Response time limit includes movement of valves and attainment of pump or blower discharge pressure.

(1)Containment Isolation response time is applicable to the valves specified in Specification 3.6.3.

TABLE 4.3-2

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTAION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
1. SAFETY INJECTION (SIAS)				
a. Manual (Trip Buttons)	N.A.	N.A.	R	1, 2, 3, 4
b. Containment Pressure - High	S	R	M	1, 2, 3
c. Pressurizer Pressure - Low	S	R	M	1, 2, 3
d. Automatic Actuation Logic	N.A.	N.A.	M(1), SA(2)	1, 2, 3, 4
2. CONTAINMENT SPRAY (CSAS)				
a. Manual (Trip Buttons)	N.A.	N.A.	R	1, 2, 3, 4
b. Containment Pressure -- High - High	S	R	M	1, 2, 3
c. Automatic Actuation Logic	N.A.	N.A.	M(1), SA(2)	1, 2, 3, 4
3. CONTAINMENT ISOLATION (CIAS)				
a. Manual CIAS (Trip Buttons)	N.A.	N.A.	R	1, 2, 3, 4
b. Safety Injection SIAS	N.A.	N.A.	R	1, 2, 3, 4
c. Containment Pressure - High	S	R	M	1, 2, 3
d. Containment Radiation - High	S	R	M	1, 2, 3
e. Automatic Actuation Logic	N.A.	N.A.	M(1), SA(2)	1, 2, 3, 4
4. MAIN STEAM LINE ISOLATION				
a. Manual (Trip Buttons)	N.A.	N.A.	R	1, 2, 3
b. Steam Generator Pressure - Low	S	R	M	1, 2, 3
c. Containment Pressure - High	S	R	M	1, 2, 3
d. Automatic Actuation Logic	N.A.	N.A.	M(1), SA(2)	1, 2, 3, 4
5. CONTAINMENT SUMP RECIRCULATION (RAS)				
a. Manual RAS (Trip Buttons)	N.A.	N.A.	R	N.A.
b. Refueling Water Storage Tank - Low	S	R	M	1, 2, 3
c. Automatic Actuation Logic	N.A.	N.A.	M(1), SA(2)	1, 2, 3

3/4.4.3 PRESSURIZER

LIMITING CONDITION FOR OPERATION

3.4.3 The pressurizer shall be OPERABLE with a minimum water level of greater than or equal to 27% indicated level and a maximum water level of less than or equal to 68% indicated level and at least two groups of pressurizer heaters capable of being powered from 1E buses each having a nominal capacity of at least 150 kW.

APPLICABILITY: MODES 1, 2, and 3.

ACTION:

a. With one group of the above required pressurizer heaters inoperable, restore at least two groups to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

b. With the pressurizer otherwise inoperable, be in at least HOT STANDBY with the reactor trip breakers open within 6 hours and in HOT SHUTDOWN within the following 6 hours.

SURVEILLANCE REQUIREMENTS

4.4.3.1 The pressurizer water volume shall be determined to be within its limits at least once per 12 hours.

4.4.3.2 The capacity of each of the above required groups of pressurizer heaters shall be verified to be at least 150 kW at least once per 92 days.

4.4.3.3 The emergency power supply for the pressurizer heaters shall be demonstrated OPERABLE at least once per 18 months by verifying that on an Engineered Safety Features Actuation test signal concurrent with a loss of offsite power:

a. the pressurizer heaters are automatically shed from the emergency power sources, and

b. the pressurizer heaters can be reconnected to their respective buses manually from the control room.

3/4.4.4 PORV BLOCK VALVES

LIMITING CONDITION FOR OPERATION

3.4.4 Each Power Operated Relief Valve (PORV) Block valve shall be OPERABLE. No more than one block valve shall be open at any one time.

APPLICABILITY: MODES 1, 2, and 3.

ACTION:

a. With one or more block valve(s) inoperable, within 1 hour either restore the block valve(s) to OPERABLE status or close the block valve(s) and remove power from the block valve(s); otherwise, be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

b. With both block valves open, close one block valve within 1 hour, otherwise be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

c. The provisions of specification 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.4.4 Each block valve shall be demonstrated OPERABLE at least once per 92 days by operating the valve through one complete cycle of full travel unless the block valve is closed with power removed in order to meet the requirements of Action a. or b. above.

3/4.7 PLANT SYSTEMS

3/4.7.1 TURBINE CYCLE

SAFETY VALVES

LIMITING CONDITION FOR OPERATION

3.7.1.1 All main steam line code safety valves shall be OPERABLE.

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 Each main steam line code safety valve shall be demonstrated OPERABLE, with lift settings and orifice sizes as shown in Table 4.7-0, in accordance with Section XI of the ASME Boiler and Pressure Vessel Code, 1974 Edition.

TABLE 3.7-1

MAXIMUM ALLOWABLE POWER LEVEL-HIGH TRIP SETPOINT WITH INOPERABLE STEAM LINE SAFETY VALVES DURING OPERATION WITH BOTH STEAM GENERATORS

Maximum Number of Inoperable Safety Valves on Any Operating Steam Generator	Maximum Allowable Power Level-High Trip Setpoint (Percent of RATED THERMAL POWER)
1	92.8
2	79.6
3	66.3

TABLE 4.7-0

STEAM LINE SAFETY VALVES PER LOOP

VALVE NUMBER	Header A	Header B	LIFT SETTING (± 1%)	ORIFICE SIZE
a.	8201	8205	1000 psia	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	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}

AUXILIARY FEEDWATER SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.1.2 At least three independent steam generator auxiliary feedwater pumps and associated flow paths shall be OPERABLE* with:

a. Two feedwater pumps, each capable of being powered from separate OPERABLE emergency busses, and

b. One feedwater pump capable of being powered from an OPERABLE steam supply system.

APPLICABILITY: MODES 1, 2, and 3.

ACTION:

a. With one auxiliary feedwater pump inoperable, restore the required auxiliary feedwater pumps to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

b. With two auxiliary feedwater pumps inoperable be in at least HOT STANDBY within 6 hours and in HOT SHUTDOWN within the following 6 hours.

c. With three auxiliary feedwater pumps inoperable, immediately initiate corrective action to restore at least one auxiliary feedwater pump to OPERABLE status.

SURVEILLANCE REQUIREMENTS

4.7.1.2 Each auxiliary feedwater pump shall be demonstrated OPERABLE:

a. At least once per 31 days by:

1. Verifying that each motor-driven pump develops a discharge pressure of greater than or equal to 1270 psig on recirculation flow.

2. Verifying that the turbine-driven pump develops a discharge pressure of greater than or equal to 1260 psig on recirculation flow when the secondary steam supply pressure is greater than 50 psig. The provisions of Specification 4.0.4 are not applicable for entry into MODE 3.

3. Verifying that each valve (manual, power-operated, or automatic) in the flow path that is not locked, sealed, or otherwise secured in position, is in its correct position.

*The Auxiliary Feedwater System automatic initiation system shall be completely installed and OPERABLE prior to initial criticality.

MAIN STEAM LINE ISOLATION VALVES

LIMITING CONDITION FOR OPERATION

3.7.1.5 Each main steam line isolation valve shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

MODE 1 - With one main steam line isolation valve inoperable but open, POWER OPERATION may continue provided the inoperable valve is restored to OPERABLE status within 4 hours; otherwise, be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 24 hours.

MODES 2, 3 and 4 - With one main steam line isolation valve inoperable, subseqent operation in MODES 2, 3 or 4 may proceed provided:

a. The isolation valve is maintained closed.

b. The provisions of Specification 3.0.4 are not applicable.

Otherwise, be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.7.1.5 Each main steam line isolation valve shall be demonstrated OPERABLE by:

a. Part-stroke exercising the valve at least once per 92 days, and

b. Verifying full closure within 5.6 seconds on any closure actuation signal while in HOT STANDBY with $T_{avg} \geq 515°F$ during each reactor shutdown except that verification of full closure within 5.6 seconds need not be determined more often than once per 92 days.

MAIN FEEDWATER LINE ISOLATION VALVES

LIMITING CONDITION FOR OPERATION

3.7.1.6 Each main feedwater line isolation valve shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4.

ACTION:

MODE 1 - With one main feedwater line isolation valve inoperable but open, POWER OPERATION may continue provided the inoperable valve is restored to OPERABLE status within 4 hours; otherwise, be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 24 hours.

MODES 2, 3 and 4 - With one main feedwater line isolation valve inoperable, subseqent operation in MODE 2, 3, or 4 may proceed provided:

a. The isolation valve is maintained closed.

b. The provisions of Specification 3.0.4 are not applicable.

Otherwise, be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 24 hours.

SURVEILLANCE REQUIREMENTS

4.7.1.6 Each main feedwater line isolation valve shall be demonstrated OPERABLE by:

a. Part-stroke exercising the valve at least once per 92 days, and

b. Verifying full closure within 5.15 seconds on any closure actuation signal while in HOT STANDBY with $T_{avg} \geq 515°F$ during each reactor shutdown except that verification of full closure within 5.15 seconds need not be determined more often than once per 92 days.

3/4.1 REACTIVITY CONTROL SYSTEMS

BASES

3/4.1.1 BORATION CONTROL

3/4.1.1.1 and 3/4.1.1.2 SHUTDOWN MARGIN

A sufficient SHUTDOWN MARGIN ensures that 1) the reactor can be made subcritical from all operating conditions, 2) the reactivity transients associated with postulated accident conditions are controllable within acceptable limits, and 3) the reactor will be maintained sufficiently subcritical to preclude inadvertent criticality in the shutdown condition.

SHUTDOWN MARGIN requirements vary throughout core life as a function of fuel depletion, RCS boron concentration, and RCS T_{avg}. The most restrictive condition occurs at EOL, with T_{avg} at no load operating temperature, and is associated with a postulated steam line break accident and resulting uncontrolled RCS cooldown. In the analysis of this accident, a minimum SHUTDOWN MARGIN of 5.0% delta k/k is required to control the reactivity transient. Accordingly, the SHUTDOWN MARGIN requirement is based upon this limiting condition and is consistent with FSAR safety analysis assumptions. At earlier times in core life, the minimum SHUTDOWN MARGIN required for the most restrictive conditions is less than 5.0% $\Delta k/k$. With T_{avg} less than or equal to 200°F, the reactivity transients resulting from any postulated accident are minimal and a 3% delta k/k SHUTDOWN MARGIN provides adequate protection.

3/4.1.1.3 BORON DILUTION

A minimum flow rate of at least 3000 gpm provides adequate mixing, prevents stratification and ensures that reactivity changes will be gradual during boron concentration reductions in the Reactor Coolant System. A flow rate of at least 3000 gpm will circulate an equivalent Reactor Coolant System volume of 10,931 cubic feet in approximately 26 minutes. The reactivity change rate associated with boron concentration reductions will therefore be within the capability of operator recognition and control.

3/4.1.1.4 MODERATOR TEMPERATURE COEFFICIENT

The limitations on moderator temperature coefficient (MTC) are provided to ensure that the assumptions used in the accident and transient analysis remain valid through each fuel cycle. The surveillance requirements for measurement of the MTC during each fuel cycle are adequate to confirm the MTC value since this coefficient changes slowly due principally to the reduction in RCS boron concentration associated with fuel burnup. The confirmation that the measured MTC value is within its limit provides assurances that the coefficient will be maintained within acceptable values throughout each fuel cycle.

3/4.1.1.5 MINIMUM TEMPERATURE FOR CRITICALITY

This specification ensures that the reactor will not be made critical with the Reactor Coolant System average temperature less than 515°F. This limitation is required to ensure (1) the moderator temperature coefficient is within its analyzed temperature range, (2) the protective instrumentation is within its normal operating range, (3) the pressurizer is capable of being in an OPERABLE status with a steam bubble, and (4) the reactor pressure vessel is above its minimum RT_{NDT} temperature.

3/4.1.2 BORATION SYSTEMS

The boron injection system ensures that negative reactivity control is available during each mode of facility operation. The components required to perform this function include (1) borated water sources, (2) charging pumps, (3) separate flow paths, (4) boric acid makeup pumps, (5) associated heat tracing systems, and (6) an emergency power supply from OPERABLE diesel generators.

With the RCS average temperature above 200°F, a minimum of two separate and redundant boron injection systems are provided to ensure single functional capability in the event an assumed failure renders one of the systems inoperable. Allowable out-of-service periods ensure that minor component repair or corrective action may be completed without undue risk to overall facility safety from injection system failures during the repair period.

The boration capability of either system is sufficient to provide a SHUTDOWN MARGIN from expected operating conditions of 3.0% delta k/k after xenon decay and cooldown to 200°F. The maximum expected boration capability requirement occurs at EOL from full power equilibrium xenon conditions and requires boric acid solution from the boric acid makeup tanks in the allowable concentrations and volumes of Specification 3.1.2.8 or 72,000 gallons of 1720 ppm - 2100 ppm borated water from the refueling water tank.

With the RCS temperature below 200°F one injection system is acceptable without single failure consideration on the basis of the stable reactivity condition of the reactor and the additional restrictions prohibiting CORE ALTERATIONS and positive reactivity changes in the event the single injection system becomes inoperable.

The boron capability required below 200°F is based upon providing a 3% delta k/k SHUTDOWN MARGIN after xenon decay and cooldown from 200°F to 140°F. This condition requires either 4,150 gallons of 1720 ppm - 2100 ppm borated water from the refueling water tank or boric acid solution from the boric acid makeup tanks in accordance with the requirements of Specification 3.1.2.7.

The contained water volume limits includes allowance for water not available because of discharge line location and other physical characteristics.

The OPERABILITY of one boron injection system during REFUELING ensures that this system is available for reactivity control while in MODE 6.

The limits on contained water volume and boron concentration of the RWT also ensure a pH value of between 7.0 and 11.0 for the solution recirculated within containment after a LOCA. This pH band minimizes the evolution of iodine and minimizes the effect of chloride and caustic stress corrosion on mechanical systems and components.

3/4.1.2.9 BORON DILUTION

The simultaneous use of the boronometer and RCS sampling at intervals dependent upon the MODE and the number of OPERABLE charging pumps to monitor the RCS boron concentration provides diverse and redundant indications of an inadvertent boron dilution. This will allow detection with sufficient time for termination of the boron dilution event before a complete loss of SHUTDOWN MARGIN occurs.

3/4.1.3 MOVABLE CONTROL ASSEMBLIES

The specifications of this section ensure that (1) acceptable power distribution limits are maintained, (2) the minimum SHUTDOWN MARGIN is maintained, and (3) the potential effects of CEA misalignments are limited to acceptable levels.

The ACTION statements which permit limited variations from the basic requirements are accompanied by additional restrictions which ensure that the original design criteria are met.

The ACTION statements applicable to a stuck or untrippable CEA, to two or more inoperable CEAs and to a large misalignment (greater than or equal to 15 inches) of two or more CEAs, require a prompt shutdown of the reactor since either of these conditions may be indicative of a possible loss of mechanical functional capability of the CEAs and in the event of a stuck or untrippable CEA, the loss of SHUTDOWN MARGIN.

For small misalignments (less than 15 inches) of the CEAs, there is (1) a small effect on the time-dependent long-term power distributions relative to those used in generating LCOs and LSSS setpoints, (2) a small effect on the available SHUTDOWN MARGIN, and (3) a small effect on the ejected CEA worth used in the safety analysis. Therefore, the ACTION statement associated with small misalignments of CEAs permits a 1-hour time interval during which attempts may be made to restore the CEA to within its alignment requirements. The 1-hour time limit is sufficient to (1) identify causes of a misaligned CEA, (2) take appropriate corrective action to realign the CEAs, and (3) minimize the effects of xenon redistribution.

MOVABLE CONTROL ASSEMBLIES (Continued)

Overpower margin is provided to protect the core in the event of a large misalignment ($\geq$ 15 inches) of a CEA. However, this misalignment would cause distortion of the core power distribution. This distribution may, in turn, have a significant effect on (1) the available SHUTDOWN MARGIN, (2) the time-dependent long-term power distributions relative to those used in generating LCOs and LSSS setpoints, and (3) the ejected CEA worth used in the safety analysis. Therefore, the ACTION statement associated with the large misalignment of a CEA requires a prompt realignment of the misaligned CEA.

The ACTION statements applicable to misaligned or inoperable CEAs include requirements to align the OPERABLE CEAs in a given group with the inoperable CEA. Conformance with these alignment requirements bring the core, within a short period of time, to a configuration consistent with that assumed in generating LCO and LSSS setpoints. However, extended operation with CEAs significantly inserted in the core may lead to perturbations in (1) local burnup, (2) peaking factors, and (3) available shutdown margin which are more adverse than the conditions assumed to exist in the safety analyses and LCO and LSSS setpoints determination. Therefore, time limits have been imposed on operation with inoperable CEAs to preclude such adverse conditions from developing.

The requirement to reduce power in certain time limits depending upon the previous F_r^T is to eliminate a potential nonconservatism for situations when a CEA has been declared inoperable. A worst-case analysis has shown that a DNBR SAFDL violation may occur during the second hour after the CEA misalignment if this requirement is not met. This potential DNBR SAFDL violation is eliminated by limiting the time operation is permitted at full power before power reductions are required. These reductions will be necessary once the deviated CEA has been declared inoperable. This time allowed to continued operation at a reduced power level can be permitted for the following reasons:

1. The margin calculations which support the Technical Specifications are based on a steady-state radial peak of $F_r^T = 1.70$.

2. When the actual $F_r^T < 1.70$, significant additional margin exists.

3. This additional margin can be credited to offset the increase in F_r^T with time that can occur following a CEA misalignment.

4. This increase in F_r^T is caused by xenon redistribution.

5. The present analysis can support allowing a misalignment to exist for up to 63 minutes without correction, if the initial $F_r^T \leq 1.54$.

3/4.2 POWER DISTRIBUTION LIMITS

BASES

3/4.2.1 LINEAR HEAT RATE

The limitation on linear heat rate ensures that in the event of a LOCA, the peak temperature of the fuel cladding will not exceed 2200°F.

Either of the two core power distribution monitoring systems, the Excore Detector Monitoring System and the Incore Detector Monitoring System, provides adequate monitoring of the core power distribution and are capable of verifying that the linear heat rate does not exceed its limits. The Excore Detector Monitoring System performs this function by continuously monitoring the AXIAL SHAPE INDEX with the OPERABLE quadrant symmetric excore neutron flux detectors and verifying that the AXIAL SHAPE INDEX is maintained within the allowable limits of Figure 3.2-2. In conjunction with the use of the excore monitoring system and in establishing the AXIAL SHAPE INDEX limits, the following assumptions are made: (1) the CEA insertion limits of Specifications 3.1.3.5 and 3.1.3.6 are satisfied, (2) the flux peaking augmentation factors are as shown in Figure 4.2-1, (3) the AZIMUTHAL POWER TILT restrictions of Specification 3.2.4 are satisfied, and (4) the TOTAL PLANAR RADIAL PEAKING FACTOR does not exceed the limits of Specification 3.2.2.

The Incore Detector Monitoring System continuously provides a direct measure of the peaking factors and the alarms which have been established for the individual incore detector segments ensure that the peak linear heat rates will be maintained within the allowable limits of Figure 3.2-1. The setpoints for these alarms include allowances, set in the conservative directions, for (1) flux peaking augmentation factors as shown in Figure 4.2-1, (2) a measurement-calculational uncertainty factor of 1.062, (3) an engineering uncertainty factor of 1.03, (4) an allowance of 1.01 for axial fuel densification and thermal expansion, and (5) a THERMAL POWER measurement uncertainty factor of 1.02.

3/4.2.2, 3/4.2.3 and 3/4.2.4 TOTAL PLANAR AND INTEGRATED RADIAL PEAKING FACTORS - F^T_{xy} AND F^T_r AND AXIMUTHAL POWER TILT - T_q

The limitations on F^T_{xy} and T_q are provided to ensure that the assumptions used in the analysis for establishing the Linear Heat Rate and Local Power Density - High LCOs and LSSS setpoints remain valid during operation at the various allowable CEA group insertion limits. The limitations on F^T_r and T_q are provided to ensure that the assumptions used in the analysis establishing the DNB Margin LCO, the Thermal Margin/Low Pressure LSSS setpoints remain valid during operation at the various allowable CEA group insertion limits. If F^T_{xy}, F^T_r or T_q exceed their basic limitations, operation may continue under the additional restrictions imposed by the ACTION statements since these additional restrictions provide adequate provisions to assure that the assumptions used in establishing the Linear Heat Rate, Thermal Margin/Low Pressure and Local Power Density - High LCOs and LSSS setpoints remain valid.

An AZIMUTHAL POWER TILT > 0.10 is not expected and if it should occur, subsequent operation would be restricted to only those operations required to identify the cause of this unexpected tilt.

The requirement that the measured value of Tq be mutiplied by the calculated values of F_r and F_{xy} to determine F_r^T and F_{xy}^T is applicable only when F_r and F_{xy} are calculated with a non-full core power distribution analysis code. When monitoring a reactor core power distribution, F_r or F_{xy} with a full core power distribution analysis code the azimuthal tilt is explicitly accounted for as part of the radial power distribution used to calculate F_{xy} and F_r.

The Surveillance Requirements for verifying that F_{xy}^T, F_r^T and T_q are within their limits provide assurance that the actual values of F_{xy}, F_r and T_q do not exceed the assumed values. Verifying F_{xy}^T and F_r^T after each fuel loading prior to exceeding 75% of RATED THERMAL POWER provides additional assurance that the core was properly loaded.

3/4.2.5 DNB PARAMETERS

The limits on the DNB-related parameters assure that each of the parameters are maintained within the normal steady-state envelope of operation assumed in the transient and safety analyses. The limits are consistent with the safety analyses assumptions and have been analytically demonstrated adequate to maintain a minimum DNBR of $\geq$ 1.28 throughout each analyzed transient.

The 12-hour periodic surveillance of these parameters through instrument readout is sufficient to ensure that the parameters are restored within their limits following load changes and other expected transient operation. The 18-month periodic measurement of the RCS total flow rate is adequate to detect flow degradation and ensure correlation of the flow indication channels with measured flow such that the indicated percent flow will provide sufficient verification of flow rate on a 12-hour basis.

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3/4.7 PLANT SYSTEMS

BASES

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)

3/4.7.1.2 AUXILIARY FEEDWATER SYSTEM

The OPERABILITY of the auxiliary feedwater system ensures that the Reactor Coolant System can be cooled down to less than 350°F from normal operating conditions in the event of a total loss-of-offsite power.

Each electric-driven auxiliary feedwater pump is capable of delivering a total feedwater flow of 320 gpm at a pressure of 1000 psia to the entrance of the steam generators. The steam-driven auxiliary feedwater pump is capable of delivering a total feedwater flow of 500 gpm at a pressure of 1000 psia to the entrance of the steam generators. This capacity is sufficient to ensure that adequate feedwater flow is available to remove decay heat and reduce the Reactor Coolant System temperature to less than 350°F when the shutdown cooling system may be placed into operation.

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 to maintain the Unit 2 RCS at HOT STANDBY conditions for 4 hours followed by an orderly cooldown to the shutdown cooling entry temperature (350°F). The contained water volume limit includes an allowance for water not usable because of tank discharge line location or other physical characteristics.

The actual water requirements are 149,500 gallons for Unit 2 and 125,000 gallons for Unit 1. Included in the required volumes of water are the tank unusable volume of 9400 gallons and a conservative allowance for instrument error of 21,400 gallons.

5.0 DESIGN FEATURES

5.1 SITE

EXCLUSION AREA

5.1.1 The exclusion area shall be as shown in Figure 5.1-1.

LOW POPULATION ZONE

5.1.2 The low population zone shall be as shown in Figure 5.1-1.

5.2 CONTAINMENT

CONFIGURATION

5.2.1 The reactor containment building is a steel building of cylindrical shape, with a dome roof and having the following design features:

a. Nominal inside diameter = 140 feet.

b. Nominal inside height = 232 feet.

c. Net free volume = 2.506×10^6 cubic feet.

d. Nominal thickness of vessel walls = 2 inches.

e. Nominal thickness of vessel dome = 1 inch.

f. Nominal thickness of vessel bottom = 2 inches.

5.2.1.2 SHIELD BUILDING

a. Minimum annular space = 4 feet.

b. Annulus nominal volume = 543,000 cubic feet.

c. Nominal outside height (measured from top of foundation mat to the top of the dome) = 228.5 feet.

d. Nominal inside diameter = 148 feet.

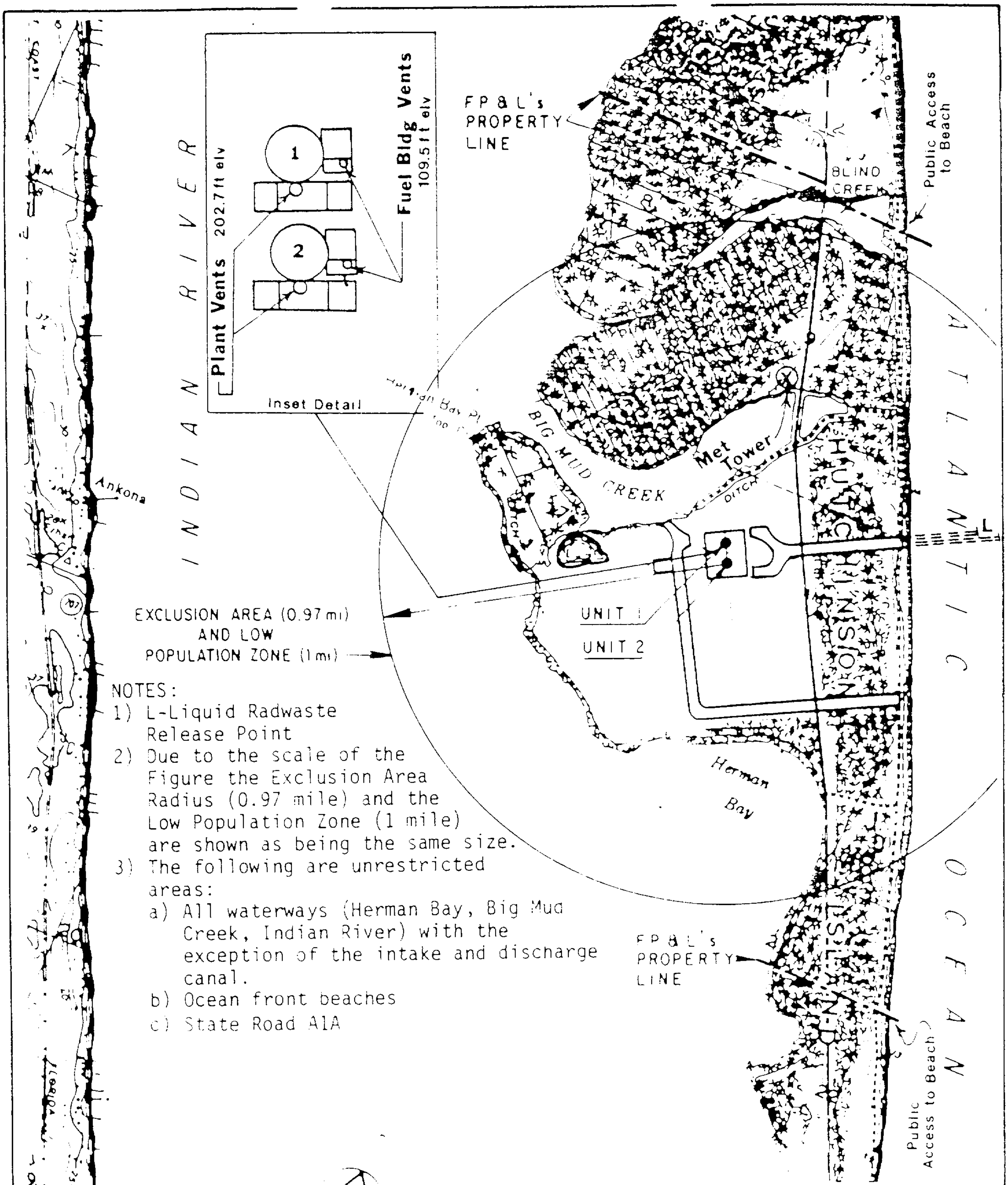
e. Cylinder wall minimum thickness = 3 feet.

f. Dome minimum thickness = 2.5 feet.

g. Dome inside radius = 112 feet.

DESIGN PRESSURE AND TEMPERATURE

5.2.2 The steel reactor containment building is designed and shall be maintained for a maximum internal pressure of 44 psig and a temperature of 264°F.



FLORIDA POWER & LIGHT COMPANY
ST. LUCIE PLANT

SITE AREA MAP

FIGURE 5.1-1

5.3 REACTOR CORE

FUEL ASSEMBLIES

5.3.1 The reactor core shall contain 217 fuel assemblies with each fuel assembly containing 236 fuel and poison rod locations. All fuel and poison rods are clad with Zircaloy-4. Each fuel rod shall have a nominal active fuel length of 136.7 inches and contain approximately 1700 grams uranium. The initial core loading shall have a maximum enrichment of 2.73 weight percent U-235. Reload fuel shall be similar in physical design to the initial core loading and shall have a maximum enrichment of 3.70 weight percent U-235.

CONTROL ELEMENT ASSEMBLIES

5.3.2 The reactor core shall contain 91 full-length control element assemblies and no part-length control element assemblies.

5.4 REACTOR COOLANT SYSTEM

DESIGN PRESSURE AND TEMPERATURE

5.4.1 The Reactor Coolant System is designed and shall be maintained:

a. In accordance with the code requirements specified in Section 5.2 of the FSAR with allowance for normal degradation pursuant of the applicable Surveillance Requirements,

b. For a pressure of 2485 psig, and

c. For a temperature of 650°F, except for the pressurizer which is 700°F.

VOLUME

5.4.2 The total water and steam volume of the reactor coolant system is 10,931 ± 275 cubic feet at a nominal T_{avg} of 572°F.

5.5 METEOROLOGICAL TOWER LOCATION

5.5.1 The meteorological tower shall be located as shown on Figure 5.1-1.

5.6 FUEL STORAGE

CRITICALITY

5.6.1

a. The spent fuel storage racks are designed and shall be maintained with:

1. A k_{eff} equivalent to less than or equal to 0.95 when flooded with unborated water, which includes a conservative allowance of 0.024 Δk_{eff} for Total Uncertainty.

2. A nominal 8.96 inch center-to-center distance between fuel assemblies placed in the storage racks.

3. A boron concentration greater than or equal to 1720 ppm.

Region I can be used to store fuel which has a U-235 enrichment less than or equal to 4.5 weight percent. Region II can be used to store fuel which has achieved sufficient burnup such that storage in Region I is not required. The initial enrichment vs. burnup requirements of Figure 5.6-1 shall be met prior to storage of fuel assemblies in Region II.

b. The new fuel storage racks are designed for dry storage of unirradiated fuel assemblies having a U-235 enrichment less than or equal to 4.5 weight percent, while maintaining a k_{eff} of less than or equal to 0.98 under the most reactive condition.

DRAINAGE

5.6.2 The spent fuel storage pool is designed and shall be maintained to prevent inadvertent draining of the pool below elevation 56 feet.

CAPACITY

5.6.3 The spent fuel storage pool is designed and shall be maintained with a storage capacity limited to no more than 1076 fuel assemblies.

5.7 COMPONENT CYCLIC OR TRANSIENT LIMITS

5.7.1 The components identified in Table 5.7-1 are designed and shall be maintained within the cyclic or transient limits of Table 5.7-1.

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION
SUPPORTING AMENDMENT NO. 8
TO FACILITY OPERATING LICENSE NO. NPF-16
FLORIDA POWER AND LIGHT COMPANY, ET AL.
ST. LUCIE UNIT 2
DOCKET NO. 50-389

1.0 INTRODUCTION

By letter dated June 4, 1984, the Florida Power and Light Company (FP&L) submitted a request to reload and operate St. Lucie Plant Unit No. 2 for Cycle 2 (Ref. 1). In support of the request, the licensee submitted a reload safety analysis report (Ref. 2) and a statistical combination of uncertainties (SCU) methodology report (Ref. 3) applicable to St. Lucie 2.

The staff has reviewed the application and the supporting documents and has prepared the following evaluation of the fuel design, nuclear design, and thermal-hydraulic design of the core as well as an evaluation of those plant transients that were reanalyzed for Cycle 2. In addition, a summary and an evaluation of the Technical Specification changes reviewed are also presented.

Although the analyses incorporate and bound operation for core power levels up to 2700 MWt, this evaluation approves continued operation of St. Lucie 2 during its second fuel cycle at a power rating of 2560 MWt, the same core power level approved and licensed for the initial fuel cycle operation. Approval for operation at 2700 MWt would require an additional application for license amendment which we understand will be submitted in the near future.

2.0 FUEL DESIGN

2.1 Mechanical Design

The Cycle 2 core consists of 137 Batch B and C fuel assemblies irradiated during the first cycle in addition to 80 fresh Batch D assemblies. Except for the design features listed below, the mechanical design of the Batch D assemblies is identical to that of the Cycle 1 fuel assemblies. These refinements were made for the purpose of increasing margins for shoulder gap change and fuel assembly growth.

1. The fuel rod overall length has been reduced by 0.3 inches by shortening the plenum length. This results in additional shoulder gap clearance. The analysis of fuel rod internal pressure due to the shorter plenum length was performed with the fuel performance code, FATES3 (Refs. 4 and 5), which has been approved by the staff (Ref. 6). The calculations were performed assuming a larger rod plenum reduction than will occur for Cycle 2 and using conservatively high radial peaking factors versus pin burnup. The results indicate that the internal rod pressure will remain below the system pressure of 2250 psia for burnups up to 60,000 MWD/MTU. Therefore, the staff concludes that the effect of the shorter plenum length on Batch D rod internal pressure satisfies the NRC fuel rod pressure criterion.

2. The fuel assembly guide tube has been changed from cold worked to annealed material. This will result in a lower growth rate of the fuel assembly and is, therefore, acceptable.

3. The guide tube overall length has been increased by 0.4 inches. This produces a corresponding raising of the upper end fitting that results in additional shoulder gap clearance. Although the longer annealed guide tube may begin operation with a higher spring loading on the fuel assembly, the lower growth rate for annealed guide tubes will minimize the change in spring compressive force with increasing burnup. This change is, therefore, acceptable.

The licensee has stated that the cladding creep collapse time for any fuel that will be irradiated during Cycle 2 was conservatively determined to be greater than its maximum projected residence time. The creep collapse analysis was performed by Combustion Engineering (CE) using the CEPAN computer code (Ref. 7) which has been approved for licensing applications. The staff concludes that cladding collapse has been appropriately considered and will not occur for Cycle 2 operation.

Cycle 2 will consist of 73 Batch B assemblies and 64 Batch C assemblies. All Batch C assemblies and 16 Batch B assemblies have been shimmed to increase the initial shoulder gap clearance from 0.997 inches to 1.447 inches. The licensee has concluded that this increase is sufficient to assure at least 95% confidence of adequate shoulder gap clearance during Cycle 2 operation. This conclusion was based on Arkansas Nuclear One Unit 2 (ANO-2) measured shoulder gap closure in conjuction with predicted fluences to evaluate shoulder gap. Cycle 2 will also include 57 Batch B unshimmed assemblies with an initial shoulder gap of 0.997 inches. During the Cycle 1-2 outage, verification of an adequate shoulder gap for a second cycle of operation for these assemblies will take place by conducting shoulder gap measurements in conjunction with supporting analysis. Those assemblies that fail to show adequate shoulder gap for the Cycle 2 operation will be shimmed at the site. A formal report addressing this will be submitted to the NRC prior to Cycle 2 startup, as required by the St. Lucie 2 license condition on axial growth.

2.2 Thermal Design

The thermal performance of Cycle 2 fuel was performed by the licensee by analyzing a composite fuel pin that envelopes the various fuel assemblies (fuel Batches B, C, and D) in the Cycle 2 core using FATES3. The NRC-imposed grain size restriction (Ref. 6) was included and a power history that envelopes the power and burnup levels representative of the peak pin at each burnup interval from beginning-of-cycle (BOC) to end-of-cycle (EOC) was used. The power-to-centerline melt limit, determined by FATES3, takes credit for decreased power peaking that is characteristic of highly burned fuel. Since a decrease in fuel melt temperature accompanies burnup, the most limiting power-to-centerline melt was found to occur at an intermediate burnup range.

Using conservative estimates of the burnup point at which the power peaking begins to decrease and the rate at which it decreases for Cycle 2, the most limiting power-to-centerline melt has been determined to be in excess of 22 kW/ft. Since approved methods and acceptable assumptions were used and this value has been incorporated into the proposed Technical Specifications and used in the safety analyses, the staff finds that the power-to-centerline melt limit of 22 kW/ft is acceptable.

3.0 NUCLEAR DESIGN

3.1 Fuel Management

The St. Lucie 2 Cycle 2 core consists of 217 fuel assemblies, each having a 16x16 fuel rod array. All of the 73 Batch A assemblies and 7 Batch B assemblies initially loaded in Cycle 1 will be removed and*replaced by 24 Batch B assemblies (3.65 w/o U-235 enrichment), 16 Batch D assemblies (3.65 w/o U-235 enrichment) containing 4 burnable poison shims per assembly, and 40 Batch D/ assemblies (3.65 w/o U-235 enrichment) containing 8 burnable poison shims per assembly. The revised high density fuel storage racks as well as the fresh fuel storage racks have been approved for storage of fuel of maximum U-235 enrichment of 4.5 weight percent.

The Cycle 2 core will utilize a low leakage fuel management scheme to reduce the uranium requirements for a specified total energy output. This is achieved by the loading of several once-irradiated Batch B and C assemblies on the core periphery and the inboard loading of most of the fresh Batch D assemblies. This scheme has been approved for many recent reload cores and has been accounted for in the calculation of the Cycle 2 core physics parameters. It is, therefore, acceptable.

The nuclear design and safety analysis for Cycle 2 is based on a Cycle 1 length of between 8,250 to 10,000 effective full power hours (EFPH). The analyses presented by the licensee will accommodate a Cycle 2 length up to 10,000 EFPH at a core power of 2700 MWt. This evaluation, however, approves continued operation of Unit 2 during its second cycle at a power rating of 2560 MWt, the same level approved and licensed for the initial fuel cycle operation.

3.2 Power Distributions

Hot full power (HFP) fuel assembly relative power densities are given in Reference 2 for beginning-of-cycle (BOC), middle-of-cycle (MOC), and end-of-cycle (EOC) conditions and for unrodded and rodded (CEA Bank 5 in) configurations. These results show that the Technical Specification limits on radial peaking factors bound the values expected to occur throughout the entire cycle. These expected values are based on three-dimensional ROCS code coarse-mesh and two-dimensional PDQ code fine-mesh core depletion calculations that have been approved previously by the NRC staff and are, therefore, acceptable.

3.3 Control Requirements

The value of the most restrictive required shutdown margin is determined by the EOC hot zero power (HZP) steam line break analysis and the resulting uncontrolled reactor coolant system (RCS) cooldown. A minimum shutdown margin of 5.0% k/k is required to control the reactivity transient. Based on this value of required shutdown margin and on calculated available scram reactivity including a maximum worth stuck control element assembly (CEA) and appropriate calculational uncertainties, sufficient excess exists between available and required scram reactivity to meet the Technical Specification limiting condition for operation (LCO). For operating temperatures below 200°F, the reactivity transients resulting from any postulated accident are minimal and a 3% k/k shutdown margin has been found to provide adequate protection. These results are derived by approved methods and incorporate appropriate assumptions and are, therefore, acceptable.

The CEA configuration for Cycle 2 differs from that of the reference cycle in several respects. These changes were made primarily to enchance operational characteristics such as control of axial shape index (ASI) and will also result in an increase in the available shutdown margin. Eight additional CEAs will be installed in the empty part length CEA drives since Cycle 2 contains no part length rods. The CEA banks and subgroups have been reconfigured and a new lead bank has been installed consisting of 12 reduced strength CEAs. Each of these consist of two B_4C fingers and three Al_2O_3 fingers. This will increase the number of CEAs from 4 to 12 in the first sequentially inserted group during reactor control maneuvers. The 91 CEAs available will now be subdivided into five regulating and two shutdown banks.

The effects of these CEA configuration changes have been properly accounted for in the safety analyses and in the Technical Specifications and have been derived using approved methods. Therefore, the staff finds the changes acceptable.

4.0 THERMAL-HYDRAULIC DESIGN

Steady-state thermal hydraulic analysis for Cycle 2 is performed using the approved core thermal hydraulic code TORC and the CE-1 critical heat flux (CHF) correlation. The core and hot channel are modeled with the approved method described in Ref. 8. The design thermal margin analysis is performed using the fast running variation of the TORC code, CETOP-D (Ref. 9). In response to the staff's request, the licensee has shown that the CETOP-D model predicts minimum DNBR conservatively relative to TORC (Ref. 10).

The uncertainties associated with the system parameters are combined statistically using the approved statistical combination of uncertainties (SCU) methodology described in Refs. 11, 12, and 13. Using this SCU methodology, the engineering hot channel factors for heat flux, heat input, rod pitch and cladding diameter are combined statistically with other uncertainty factors to arrive at an equivalent DNBR limit of 1.28 at a 95/95 probability/confidence limit. It has been calculated using the approved method described in Ref. 14. The value used for this analysis, 1.75% MDNBR, is valid for bundle burnups up to 30,000 MWD/MTU. For those asemblies with an assembly average burnup in excess of 30,000 MWD/MTU, the minimum best estimate margin available, relative to more limiting peaking values present in other assemblies, exceeds the corresponding rod bow penalties based on Ref. 14. Therefore, the staff concurs that sufficient available margin exists to offset rod bow penalties for assemblies with burnup greater than 30,000 MWD/MTU.

5.0 TECHNICAL SPECIFICATION CHANGES - Fuels, Physics, and Thermal-Hydraulics

The staff has reviewed the proposed modifications to the Technical Specifications for Cycle 2 operation as presented in Reference 1. The staff evaluation follows:

1. Specification 2.1.1.2 - The peak linear heat to centerline melt limit has been changed from 21.0 kW/ft to 22.0 kW/ft. This change is acceptable as discussed in Section 2.2 of this Safety Evaluation (SE).

2. Figure 2.1-1 - The thermal limit lines have been revised. This change reflects the approved reanalysis at 2700 MWT, the approved Technical Specification radial peaking factors and the implementation of approved margin recovery programs and is, therefore, acceptable.

3. Table 2.2-1 - The design reactor coolant flow has been changed from 370,000 gpm to 363,000 gpm. This is acceptable since all analyses that are sensitive to minimum flow requirements have been reanalyzed using the lower flow rate and have been reviewed and approved.

4. Figure 2.2-3 - The TM/LP LSSS has been revised. This change reflects the approved analysis at 2700 MWt, the approved Technical Specification radial peaking factors and the implementation of approved margin recovery programs and is, therefore, acceptable.

5. Figure 2.2-4 - This change is acceptable for the same reasons stated in 4. above.

6. Specifications B2.1.1, B2.2.1, and B3/4.2.5 - The value of minimum DNBR has been changed from 1.20 to 1.28. The new DNB limit has been derived using the Statistical Combination of Uncertainties (SCU) methodology (Ref. 3) which has been reviewed and approved in Section 7.0 of this SE and is therefore, acceptable. The initial request by FP&L to replace the actual minimum DNBR value by the phrase "the acceptable minimum DNBR limit" has been refused. The staff requires the bases to include both the value of 1.28 as well as reference to the use of SCU in its derivation.

7. Figure B2.1-1 - The axial power distributions used for thermal margin safety limits have been revised. This is acceptable since it reflects the approved higher radial peaking for Cycle 2 and the distributions have been derived using approved methods.

8. Specifications 3.1.1.2, 3.1.2.2, 3.1.2.4, 3.1.2.6, 3.1.2.8, B3/4.1.1.1, B3/4.1.1.2, B3/4.1.2 - The shutdown margin below 200°F has been changed from 2.0% k/k to 3.0% k/k. This is acceptable since it is consistent with the assumptions used in the approved safety reanalyses for those events that are affected by the change in shutdown margin.

9. Specification 3.1.3.1 - The number of CEA regulating groups has been changed from 6 to 5. This is acceptable for the reasons discussed in Section 3.3 of this SE.

10. Specification 3.1.3.1 - The time constraints on misaligned CEA have been revised to reflect a newly inserted figure (Fig. 3.1-1a) showing allowable time to realign a CEA vs. measured initial F_r^T. This is acceptable for the reasons stated in Section 6.4.2 in this SE concerning the CEA drop event.

11. Specification 3.1.3.4 - The CEA drop time from a fully withdrawn position to its 90% insertion position has been changed from 3.0 seconds to 2.7 seconds. This change is acceptable since it is consistent with plant measurements that have shown that the actual CEA drop time associated with a reactor trip is faster than previously assumed in the reference cycle.

12. Figure 3.1-2 - The CEA power dependent insertion limits (PDIL) have been revised. This is acceptable since it is consistent with the new CEA grouping changes discussed in Section 3.3 of this SE.

13. Figure 3.2-2 - The LHR excore LCO has been revised. This change reflects the approved reanalysis at 2700 MWt, the approved Technical Specification radial peaking factors and the implementation of approved margin recovery programs and is, therefore, acceptable.

14. Figure 3.2-3 - The allowable combinations of thermal power and F_r^T, F_{xy}^T have been revised. This revision reflects the higher peaking factors and power level used in the approved safety analyses and is, therefore, acceptable.

15. Specification 3.2.2 - The total planar radial peaking factor, F_{xy}^T, has been increased to 1.75 from 1.60. This is acceptable since it is appropriately accounted for in the nuclear design and the safety analyses and has been derived using approved methods.

16. Specification 3.2.3 - The total integrated radial peaking factor, F_r^T, has been increased to 1.70 from 1.60. This is acceptable since it is appropriately accounted for in the nuclear design and the safety analyses and has been derived using approved methods.

17. Specification 4.2.3.2, B3/4.2.2, B3/4.2.3, B3/4.2.4, and Table B3/4.2-1 - All references to rod bow penalty have been deleted. This is acceptable since the approved SCU methodology incorporates adjustments for rod bow directly in the DNBR limit rather than accounting for it explicitly in the monitoring of the radial peaking factor.

18. Figure 3.2-4 - The DNB LCO has been revised. This change reflects the approved reanalysis at 2700 MWt, the reactor coolant flow reduction to 363,000 gpm, the approved Technical Specification radial peaking factors, and the implementation of margin recovery programs and is, therefore, acceptable.

19. Table 3.2-2 - The upper bound of the cold leg temperature is increased from 548°F to 549°F and the reactor coolant flow rate is decreased from 370,000 gpm to 363,000 gpm. This is acceptable since calculations were performed to evaluate the impact of the changes on AOOs and postulated accidents and the results were found to be acceptable.

20. Table 3.3-5 - The feedwater isolation response time (total delay time) has been changed from 5.35 sec to 5.15 sec for both Containment Pressure - High and Steam Generator Pressure - Low initiating signals. This is acceptable since the surveillance requirements of specification 4.7.1.6 require verification of the 5.15 sec closure time periodically and this value has been used in the safety analyses for those transients affected by valve closing time.

21. Specification 3.4.3 - The maximum pressurizer indicated water level has been increased from 65% to 68%. This change has been accounted for in the approved analysis of a CVCS malfunction, which is the limiting event affected by this change. The change is, therefore, acceptable.

22. Specifications 3/4.7.1, B3/4.7.1.1, Table 3.7-1, and Table 3.7-2 - The pages have been revised. The changes made to maximum allowable power values reflect the revised analyses at 2700 MWt. The format of the specification has been changed to improve clarity. Therefore, these changes are acceptable.

23. Specification 3.7.1.6 - The full closure times of 5.6 sec and 5.35 sec for the main feedwater line isolation valves have been changed to 5.15 sec. These changes are acceptable since they have been assumed in the safety reanalyses. The peak containment pressure analysis used 5.15 sec as the closure time and gave acceptable results.

24. Specification B3/4.1.3 - The wording indicating at what power levels a DNBR SAFDL violation could occur has been removed and the wording on how this potential violation is eliminated has been clarified. Since the power levels at which a DNBR SAFDL violation may occur could vary slightly from cycle to cycle, this wording removal is acceptable.

25. Specification B3/4.1.3 - The steady state radial peak has been changed from 1.60 to 1.70. This is acceptable for the reasons stated in item 16 above.

26. Specification B3/4.1.3 - The reference to the actual radial peak for additional margin has been changed from $F_r^T = 1.50$ to F_r^T 1.70. Although there is a margin loss for the DNB-LSSS and the DNB-LCO due to the increased radial peaking, this is more than offset by margin gains due to the SCU, less severe axial power distributions for Cycle 2, use of a statistically based thermal hydraulic model, and a reduced required overpower margin (ROPM) for the limiting CEA subgroup drop event. The change is, therefore, acceptable.

27. Specification B3/4.1.3 - The allowable CEA misalignment time has been changed from 30 minutes for an F_r^T 1.50 to 60 minutes an initial F_r^T 1.55. This change is acceptable as it reflects the assumptions used in the reanalysis of the single CEA drop event.

28. Specification 5.3.1 - The reference to each fuel assembly containing 236 fuel rods has been changed to 236 fuel and poison rods. This is acceptable since Cycle 2 will contain assemblies with poison rods.

29. Specification 5.3.1 - The reference to a maximum total weight of 1698.5 grams uranium per fuel rod has been changed to approximately 1700 grams uranium. This is acceptable since variations in loading weights from cycle to cycle may occur and can be tolerated.

30. Specification 5.3.2 - The number of full-length CEAs contained in the core has been increased from 83 to 91. This is acceptable as it represents the addition of 8 full-length CEAs into vacant part-length CEA locations as discussed in Section 3.3 of this SE.

31. Specification 5.2.1 - The containment net free volume has been changed to 2.506×10^6 ft^3 from 2.5×10^6 ft^3. This is acceptable since it is based on a more detailed analysis of the containment net free volume.

6.0 SAFETY ANALYSIS

The design bases events (DBEs) considered in the safety analyses are categorized into two groups: anticipated operational occurrences (AOOs) and postulated accidents. All events were reanalyzed or re-evaluated for Cycle 2 to assure that the applicable criteria are met.

The AOOs are analyzed to assure that Specified Acceptable Fuel Design Limits (SAFDLs) on Departure from Nucleate Boiling (DNB) and Fuel Centerline to Melt (CTM) limits are not exceeded. These AOOs are divided into two categories. The first set requires Reactor Protection System (RPS) trips to assure that SAFDLs are not exceeded. The second set requires RPS trips and/or sufficient initial steady state margin (preserved by the LCOs) to prevent exceeding the SAFDLs. Transient analyses of the events in this latter category were performed utilizing the Statistical Combination of Uncertainties (SCU) methodology discussed in Section 7.0 of this SE.

Plant response to the DBEs was simulated using the same methods and computer programs as used and approved for Cycle 1 analyses or approved by the staff after Cycle 1 analyses. These include the CESEC III and STRIKIN II computer codes. Most events were reanalyzed to determine the effect of changes to key parameters from Cycle 1 to Cycle 2 such as an increase in rated core power, increases in radial power peaks and a lower minimum allowable reactor coolant flow.

6.1 Increase in Heat Removal Events

The licensee has evaluated the following AOOs that result in an increase in heat removal by the secondary system:

(a) decrease in feedwater temperature
(b) increase in feedwater flow
(c) increase main steam flow
(d) inadvertent opening of a steam generator safety valve or atmospheric dump valve.

The staff has reviewed the calculational models and assumptions used in the analyses of these events and find them acceptable. For all events, the maximum pressure within the reactor coolant system did not exceed 110% of the design pressure. Also, the minimum DNBR did not decrease below the design limit of 1.28 and the maximum local linear heat generation rate remained below the design limit of 22 kW/ft. The inadvertent opening of a steam generator safety valve is the limiting AOO that is analyzed for impact on offsite dose. The licensee has demonstrated conformance with the staff's acceptance criteria in the Standard Review Plan (SRP) Section 15.1.1, 15.1.2, 15.1.3, and 15.1.4. The staff, therefore, concludes that Cycle 2 operation is acceptable with respect to AOOs resulting in an increase in heat removal by the secondary system.

6.2 Decrease in Heat Removal Events

The licensee has evaluated the following AOOs that result in a decrease in heat removal by the secondary system:

(a) loss of external load
(b) turbine trip
(c) loss of condenser vacuum
(d) loss of normal AC power
(e) loss of normal feedwater

The staff has reviewed the calculational models and assumptions used in the analyses of these events and find them acceptable. The licensee has demonstrated that the limiting AOO that affects RCS pressure is the loss of condenser vacuum event. The peak RCS pressure attained is below the upset pressure limit of 110% of design pressure (2750 psia). The licensee has also shown that for the other AOOs leading to a decrease in heat removal by the secondary system, no fuel failure will occur, core geometry and CEA insertability are maintained with no loss of cooling capability, and maximum RCS pressure remains below 110% of design. The staff finds the results of these analyses in conformance with the acceptance criteria of SRP Sections 15.2.1 thru 15.2.7 and, therefore, acceptable.

6.3 Decrease in Reactor Coolant Flow Events

The licensee has analyzed both the partial and total loss of forced reactor coolant flow. The partial loss of forced reactor coolant flow is bounded by the total loss of forced reactor coolant flow and, therefore, only a detailed analysis of the latter was performed. This is the limiting AOO with respect to fuel integrity and is used to establish the minimum initial margin that must be maintained by the LCOs with respect to the DNBR limit. Therefore, this event results in an acceptable minimum DNBR of 1.28. The staff finds the plant response to a decrease in reactor coolant flow to be acceptable during Cycle 2 operation and in conformance with the staffs acceptance criteria of SRP Section 15.3.1.

6.4 Reactivity and Power Distribution Anomalies

6.4.1 Uncontrolled CEA Withdrawal Event

The licensee has analyzed the uncontrolled CEA withdrawal event from both high power and low power core conditions. The staff has reviewed the calculational models and the assumptions used in these analyses and find them acceptable. The licensee has shown that DNBR and fuel centerline melt SAFDLs are not violated and the RCS pressure remains below the upset limit. The staff, therefore, finds the results of an uncontrolled CEA withdrawal event during Cycle 2 to be in conformance with the acceptance criteria of SRP Section 15.4.1 and 15.4.2 and acceptable.

6.4.2 CEA Drop Event

The licensee has reanalyzed both the single and subgroup CEA drop event to determine the initial thermal margins that must be maintained by the LCOs such that the DNBR and CTM design limits will not be exceeded. The subgroup CEA drop was found to be more limiting. CEA withdrawal during the event is prohibited by the protection system so that power overshoot is not a problem.

The maximum initial radial peaking factor (F_r^T) assumed was the Technical Specification limit of 1.70. For the CEA subgroup drop, the maximum increase in F_r^T assumed was 19.0%. The comparable increase for a single CEA drop event is 14.0%. Therefore, the F_r^T can increase an additional 5% due to power redistribution following a single dropped CEA and still be bounded by the results of a subgroup CEA drop. The results of the licensee's analysis show that the net increase in F_r^T for the single drop after 15 minutes (18%) remains below the limiting increase in F_r^T for the subgroup drop (19%). After 63 minutes, the net increase in F_r^T is less than 19% above 1.70 when the pre-drop F_r^T is less than or equal to 1.54.

The licensee has shown that this event initiated from the Technical Specification LCOs will not exceed the DNBR and CTM design limits. The staff, therefore, finds the results to be in conformance with the acceptance criteria of SRP Section 15.4.3 and acceptable.

6.4.3 CVCS Malfunction (Inadvertent Boron Dilution)

The licensee has analyzed the boron dilution event to determine the setpoints of the startup channel alarms required for protection against loss of shutdown margin before the operator has time to stop the event. The event was analyzed from hot standby, hot shutdown, cold shutdown, and refueling conditions. The results indicate that the time available to the operator to stop the event from the alarm annunciation until criticality occurs meets the acceptance criteria stated in SRP Section 15.4.6 for minimum time from alarm annunciation to loss of shutdown margin. Therefore, the staff finds that St. Lucie 2 provides sufficient protection against inadvertent boron dilution events occurring during Cycle 2.

6.5 Increase in Reactor Coolant System Inventory

The licensee has identified the limiting increase in RCS inventory event to be the pressurizer level control system (PLCS) malfunction with a simultaneous closure of the letdown control valve to the zero flow position. This event is more limiting than the inadvertent operation of the emergency core cooling system (ECCS) because the shutoff head of the injection pumps is less than the RCS pressure during power operation. The operator has 20 minutes available after the high pressurizer level alarm occurs to prevent filling of the pressurizer. The staff finds this an acceptable period for operator action. Since operator action prevents a reactor and turbine trip, there is no event-related offsite dose and the peak RCS pressure is below 2415 psia. The increasing RCS pressure results in an increasing DNB and the fuel performance criterion is not approached. Therefore, the results of the analysis meet the acceptance criteria of SRP 15.5.1 and are acceptable.

6.6 Decrease in Reactor Coolant System Inventory

The inadvertent opening of a power operated relief valve (PORV) initiated at power was analyzed to demonstrate that this event does not result in violation of the SAFDLs and to determine a bias factor used in establishing the TM/LP trip setpoints. The event was also analyzed assuming a concurrent loss of offsite power. The minimum transient DNBR was 1.32 which is greater than the DNBR SAFDL limit of 1.28, thus no fuel failure is predicted. The plant is maintained in a stable condition due to automatic actions and, after 30 minutes, the operator opens the atmospheric dump valves and cools the plant to the point where shutdown cooling can be initiated. The staff finds the assumptions used and the analyses performed for this event to be acceptable and that the scenarios, as described by the licensee, assure that the most severe inadvertent opening of a PORV event has been considered.

6.7 Asymmetric Steam Generator Events

The four events that affect a single steam generator are:

(a) loss of load to one steam generator (LL/1SG)
(b) excess load to one steam generator (EL/1SG)
(c) loss of feedwater to one steam generator (LF/1SG)
(d) excess feedwater to one steam generator (EF/1SG)

Of these, the LL/1SG event is the limiting asymmetric event. This event is initiated by the inadvertent closure of a single main steam isolation valve (MSIV), which results in a loss of load to the affected steam generator. The asymmetric steam generator pressure trip (ASGPT) serves as the primary means of mitigating this transient with the steam generator level trip providing additional protection. The minimum transient DNBR calculated is greater than the DNBR SAFDL limit of 1.28. A maximum allowable LHGR of 18.1 kW/ft could exist as an initial condition without exceeding the fuel centerline melt SAFDL of 22.0 kW/ft during the transient. This amount of margin is assured by setting the LHR LCO based on the more limiting allowable LHR for LOCA of 13.0 kW/ft. The staff concludes that the calculations contain sufficient conservatism to assure that fuel damage will not result from any asymmetric steam generator event during Cycle 2 operation.

6.8 Conclusions

The licensee has presented results for various AOOs (with and without assumed single failures). The staff has reviewed the reanalyses and finds that they meet NRC acceptance criteria with respect to fuel and primary system performance. Therefore, adequate protection is provided for AOOs during Cycle 2 and the requirements of GDC 10, 15, and 26 are met.

6.9 Limiting Accidents

The licensee has reanalyzed events that, though not expected to occur during the lifetime of the plant, could have serious radiological consequences if not effectively mitigated. For accident conditions, the reactor coolant pressure should stay below the applicable ASME code limits. The core geometry should be maintained so that there is no loss of core cooling capability and control rod insertability. Radiological consequences must be well within the 10 CFR Part 100 limits.

6.10 Steam Systems Piping Failures Inside and Outside of Containment

Steam line breaks (SLB) inside containment may have break areas up to the cross section of the largest main steam pipe (6.305 ft^2). The licensee performed a parametric analysis in both MTC and break area and the limiting inside containment SLB event was found to be the break causing an effective flow area of 2.01 ft^2 with an effective MTC of $-.54 \times 10^{-4}$ /°F. A loss of AC power was postulated to accompany the SLB event. The results indicate that the number of fuel pins predicted to fail is less than 10% and thus a coolable geometry is maintained.

Break areas for outside containment SLBs are limited to the area of the flow restrictors (2.27 ft^2) located upstream of the containment penetrations. A parametric analysis in both MTC and break area identified the limiting event as the one which resulted in an flow area of 2.27 ft^2 with an effective MTC of -1.08×10^{-4} /°F. A loss of AC power was assumed to occur during the event. The results indicate that less than 10% of the fuel pins fail and consequently a coolable geometry is maintained. This is the most limiting postulated accident with respect to offsite dose and also with respect to fuel integrity.

The licensee has also performed analyses of the steamline break event to determine the potential for a post-trip return to power. The results of the steam line break event from HFP and HZP conditions with loss of offsite power show that there is no significant return to power.

The staff concludes that the consequences of postulated steam line break events meet the requirements of GDC 27 and 28 by demonstrating that the resultant fuel damage is limited such that CEA insertability would be maintained and that no loss of core cooling capability results. The requirements of GDC 31 and 35 demonstrating the integrity of the primary system and the adequacy of the ECCS have also been met. The parameters used as input were reviewed and found to be conservative and the model used has been previously reviewed and found acceptable by the staff. The staff, therefore, concludes that the licensee has demonstrated conformance with the acceptance criteria stipulated in SRP Section 15.1.5. As such, the staff concludes that the Cycle 2 operation is acceptable with respect to accidents resulting in breaks in the steam line.

6.11 Feedwater Line Break Event

The feedwater line break event with a loss of AC at time of high pressurizer pressure trip was analyzed. In order to maximize the radioactivity release during the transient, the analysis assumed that all of the initial activity in both steam generators and the activity added due to the primary to secondary leak rate tube leakage allowed by the Technical Specifications are released to the atmosphere with a decontamination factor of 1.0. The results show that the feedwater line break event with a loss of AC will not lead to a DNBR that is less than the design limit of 1.28 during the transient and the RCS peak presssure does not exceed 110% of design pressure. The staff, therefore, concludes that the results of a feedwater line break occurring during Cycle 2 meet the criterion of SRP Section 15.2.8 and are acceptable.

6.12 Single Reactor Coolant Pump Shaft Seizure/Sheared Shaft

The seized rotor event with loss of offsite power, Technical Specification steam generator tube leakage, failure to restore offsite power in 2 hours, and one stuck open atmospheric dump valve was analyzed. The results show that the number of fuel pins predicted to experience DNB is much less than 10%. Since only a small fraction of fuel pins fail, the staff finds that the results of a seized rotor event during Cycle 2 are acceptable and conform to the criteria of SRP Sections 15.3.3 and 15.3.4.

6.13 CEA Ejection Event

The range of initial conditions for a CEA ejection event examined by the licensee included zero power and full power with reactivity coefficients representative of BOC or EOC for these power level extremes. The analytical method employed in the reanalysis of this event is the NRC approved CE CEA ejection method. The results indicate that the maximum total energy deposited during the event is less than 280 cal/gm and, therefore, prompt fuel rupture with consequent rapid heat transfer to the coolant will not occur.

Although the licensee predicts no clad damage to occur, their criterion is an average enthalpy no greater than 200 cal/gm. The staff has continued using DNB as the criterion for clad failure. The staff has previously recommended the use of an assumed 10% amount of failed fuel in a radiological dose calculation for rod ejection transients in which DNB was not used as the clad failure mechanism and, therefore, continues to do so in this case. The predicted consequences of this event show that primary system integrity will be maintained and are, therefore, acceptable.

6.14 Loss of Coolant Accident (LOCA)

The ECCS performance evaluation for both the large break and the small break LOCA must show conformance with the acceptance criteria required by 10 CFR 50.46. The calculations were made using approved computer programs and models that meet the requirements of Appendix K to 10 CFR Part 50. The initial conditions were chosen to maximize the cladding temperature and oxidation. Containment parameters were chosen to minimize the calculated containment pressure to assure that the reflood calculations are conservatively calculated. The analyses account for an assumed amount of steam generator tube plugging of up to 300 average length tubes per steam generator.

For the large break analysis, the licensee analyzed both guillotine and slot breaks over a range of break sizes from 5.89 ft^2 to twice the flow area of the cold leg. The worst single failure is the loss of one of the low pressure safety injection (LPSI) pumps. From this analysis, the allowable peak linear heat generation rate (PLHGR) was determined to be 13.0 kW/ft with the 1.0 double ended guillotine break in the pump discharge leg identified as the limiting break. The results for Cycle 2 show a peak clad temperature of 2041°F, a peak local clad oxidation percentage of less than 13.3% and a peak core wide clad oxidation percentage of less than 0.55%. Since this meets the acceptance criteria for peak clad temperature, peak local clad oxidation percentage, and core wide clad oxidation percentage of 2200°F, 17.0%, and 1.0%, respectively, the staff concludes that operation of St. Lucie 2 with a PLHGR of 13.0 kW/ft provides acceptable results for the most limiting large break LOCA.

For the small break analysis, the licensee analyzed a spectrum of cold leg breaks in the reactor coolant pump discharge leg (0.5 ft^2, 0.1 ft^2, 0.0375 ft^2, and 0.015 ft^2). The worst single failure is the failure of one of the emergency diesel generators to start. Offsite power is assumed to be lost upon reactor trip. For an allowable PLHGR of 15.0 kW/ft, the 0.0375 ft^2 break was determined to be the limiting small break. The results show a peak clad temperature of 1740°F and a peak local clad oxidation percentage of less than 2%, which meet the acceptance criteria. The staff, therefore, concludes that operation of St. Lucie Unit 2 with a PLHGR of 15.0 kW/ft provides acceptable results for the most limiting small break LOCA.

Based on these results, the staff concludes that the LOCA analyses resulting from a spectrum of postulated piping breaks within the primary coolant pressure boundary are acceptable and meet the relevant requirements of 10 CFR 50.46 and Appendix K to 10 CFR Part 50. A comparison of the two limiting LOCA events demonstrates that the small break LOCA ECCS performance is less limiting than that for the large break LOCA performance results. Therefore, the staff concludes that operation of St. Lucie 2 with a PLHGR of 13.0 kW/ft is acceptable for Cycle 2.

7.0 STATISTICAL COMBINATION OF UNCERTAINTIES (SCU) METHODOLOGY

The procedures in the Statistical Combination of Uncertainties (SCU) methodology reviewed and approved by the NRC for St. Lucie 1 (Refs. 11, 12, and 13) have been applied by the licensee to St. Lucie 2 for Cycle 2 operation. Therefore, the review of the St. Lucie 2 SCU was directed mainly toward the plant-specific application that accommodates the differences in plant design and reactor protection systems. The methodology consists of three parts. Part 1 (Ref. 11) describes the application of the SCU methods to the development of the local power density (LPD) and TM/LP limiting safety system settings (LSSS). These are used in the analog reactor protection system to protect against fuel centerline melt and DNB. Part 2 (Ref. 12) combines the uncertainties associated with the reactor system parameters to develop a revised DNBR limit corresponding to the SAFDL to be used in the plant safety analysis and the evaluation of the LSSS and the LCOs. Part 3 (Ref. 13) uses the SCU methodology to calculate LHR and DNB LCOs.

The plant independent calculational-measurement uncertainties used in the St. Lucie 2 SCU were derived from recent data from Cycle 5 of St. Lucie 1, Cycles 5 and 6 of Calvert Cliffs 1, and Cycles 4 and 5 of Calvert Cliffs 2 which has been obtained after the SCU reports were issued. The plant specific St. Lucie 2 data for the instrument circuitry, the lead bank CEA configuration and power dependent insertion limit were used to evaluate the plant dependent uncertainties. The shape annealing factor (SAF) component of the shape index uncertainty developed for St. Lucie 1 was used for St. Lucie 2. The licensee will evaluate the need to measure the St. Lucie 2 SAFs prior to Cycle 2 startup.

The licensee has provided the St. Lucie 2 component uncertainties associated with the LPD LHR and DNB LCOs and the LHR and TM/LP LSSSs. This data is analogous to that which had been provided previously for St. Lucie 2 and approved by the NRC.

Since the uncertainty values used in this analysis have been justified with the appropriate sources and the combination of these uncertainties is performed with the approved methods, the staff concludes that the overall aggregate uncertainty factors derived for the TM/LP and LPD LSSS are acceptable.

The statistically derived MDNBR limit contains various allowances, or penalties, as described in Ref. 12. In addition to these, an additional 5% penalty on the CHF standard deviation due to the effect of prediction uncertainty in the CHF correlation in the calculation of the DNBR limit as well as a 5% code uncertainty were included. These have been required by the NRC in previous SCU reviews. After including a 1.75% MDNBR rod bow penalty plus a 0.01 DNBR penalty due to the HID-1 grid design, the MDNBR was determined to be 1.279.

The staff finds that the plant specific parameters of St. Lucie 2 have been properly applied with the SCU methodology previously reviewed and approved by the NRC and that appropriate adjustments in the form of penalties have been included. The proposed DNBR value of 1.28 still provides at least a 95% probability at a 95% confidence level that DNB does not occur on a fuel rod having that minimum DNBR. Therefore, the staff concludes that the minimum DNBR limit of 1.28 is acceptable for the St. Lucie 2 Cycle 2 reload application.

Cycle 2 operation within the DNB and LHR LCOs must provide the necessary initial DNB and LHR margins to prevent exceeding the acceptable limits during DBEs where changes in DNBR and LHR are important. The methods for statistically combining the uncertainties involved in these LCOs are similar to those used for determining the LSSS limits. In order to determine the LCO required overpower margin (ROPM), the loss of coolant flow (LOF) and full length CEA drop events were analyzed for St. Lucie 2. The licensee has determined that these two events are bounding for the DBEs requiring intervention of RPS trips and/or sufficient initial steady state thermal margin to prevent exceeding the acceptable limits. The analyses for these limiting ROPM events discussed in the safety analysis section of this SE (Sections 6.3 and 6.4.2) were initiated from nominal conditions. The ROPM calculated at nominal conditions is then combined with the incremental ROPM, defined by these SCU transient analyses to determine the final ROPM, which must be incorporated into the protection and monitoring system setpoints.

The cycle independent maximum incremental ROPM deviations determined by these SCU transient analyses were developed using the methodology previously reviewed and approved in Ref. 13. The results appear to be consistent with the results reported therein. Therefore, the staff concludes that the statistically combined uncertainties described for St. Lucie 2 are acceptable for the DNB and LHR LCO calculations.

The application of the SCU methods described is acceptable for the St. Lucie 2 reload calculations. The overall aggregate uncertainties presented for the TM/LP LSSS and LPD LSSS are acceptable for the St. Lucie 2 trip setpoint calculations. The SCU equivalent minimum DNBR limit of 1.28 is acceptable for the reload analyses. The statistically combined uncertainties presented for the DNB and LHR LCO calculations are acceptable. However, if future reloads use computer codes and correlations other than those described in this application, a reanalysis of the aggregate uncertainties for the LSSS and LCO and the minimum DNBR limit will be required.

8.0 EVALUATION FINDINGS - Fuels, Physics, and Thermal-Hydraulics

The staff has reviewed the fuels, physics and thermal-hydraulics information presented in the St. Lucie 2 Cycle 2 reload report, the Technical Specification revisions, and the safety reanalyses and the uncertainties derived for St. Lucie 2 Cycle 2 by the SCU methodology. Based on the evaluations given in the preceding sections, the staff finds the proposed reload and associated modified Technical Specifications acceptable.

There is a license condition resulting from the staff review of fuel rod axial growth that is discussed in Section 2.1 of this SE. A formal report addressing this will be submitted by the licensee to the NRC prior to Cycle 2 startup.

9.0 CONTAINMENT

9.1 Containment Evaluation and Findings

In the licensee's report, the impact of a proposed power upgrade from 2560 to 2700 MWt on the various containment related analyses was presented. The affected analyses include the containment pressure and temperature response for the design basis LOCA and MSLB, subcompartment pressurization, ECCS back pressure calculation, and hydrogen generation. As a result of the containment analysis, several changes to the plant Technical Specifications are necessary to accommodate the proposed power increase. These changes are addressed in Section 9.2, herein.

The licensee has performed containment analyses similar to those presented in the FSAR for Cycle 1 operation. The most limiting LOCA and MSLB cases identified in the FSAR, were reanalyzed by the licensee. In so doing, the mass and energy release data were changed to reflect the increase in power level; the containment spray actuation setpoint, start time and flow rate were adjusted to compensate for the revised blowdown data. The staff has reviewed the initial conditions and assumptions used for peak containment pressure and temperature calculations and finds them acceptable. The calculated peak containment pressure and temperature for the MSLB accident are 43.7 psig and 413.9°F, respectively, and for the LOCA are 42.7 psig and 265.8°F, respectively. These values are below the design conditions of 44 psig and 420°F.

The licensee has also evaluated the impact of the power upgrade on subcompartment loading. Based on the large margin to design (> 100%) of the compartment loading, shown in the FSAR, and the small increase (< 0.5%) in the peak pressure in the containment reanalysis, the licensee concludes that the subcompartment loading would remain below design values; the staff concurs with the licensee's conclusion.

The impact of the power increase on the post-LOCA hydrogen build-up inside containment has been re-analyzed. Results of the analysis show that a single recombiner started 50 hours after the accident is sufficient to limit the hydrogen concentration in containment to below the Regulatory Guide 1.7 lower flammability limit of 4.0 volume percent. The administrative procedures described in the FSAR Section 6.2.5.2.2 require the operator to start the recombiner within 24 hours following a LOCA. In addition, the operator is alerted by alarms from the containment hydrogen analyzer system at 3.0% hydrogen concentration, which should occur no sooner than about 50 hours after onset of the accident. Based on the foregoing discussion, the staff concurs with the licensee that the existing combustible gas control system is capable of preventing the hydrogen gas concentration inside containment from exceeding the lower flammability limit.

9.2 Technical Specification Changes - Containment

1. The containment spray high-high trip setpoint has been lowered from 9.30 psig to 5.40 psig, and the allowable value has been lowered from 9.40 psig 5.50 psig. Lowering of the containment spray setpoint will result in lower peak containment pressures following mass and energy releases to the containment under power increase conditions. For the containment reanalysis, a conservative trip setpoint value of 6.0 psig was used for containment spray actuation, and the calculated peak containment pressure was below the design value. The staff, therefore, finds the proposed change in the containment spray trip setpoint acceptable.

2. The allowable response time for containment pressure instrumentation has been reduced from 1.55 seconds to 1.15 seconds. This reduction in response time is based on in-plant experience with instrument performance; therefore, the staff finds this change acceptable.

3. The high containment pressure trip setpoint for actuation of Engineered Safety Features (ESF) functions has been lowered from 5.0 psig to 4.7 psig, with the allowable value being reduced from 5.1 psig to 4.8 psig. The ESF functions affected include safety injection, containment isolation, and main steam line isolation. With regard to containment isolation, Item II.E.4.2 of NUREG-0737 recommends that the containment setpoint pressure for initiating the isolation of non-essential lines penetrating containment be reduced to the minimum value compatible with normal operating conditions. Based on a telecon with the licensee on October 25, 1984, a setpoint of 3.5 psig, instead of 4.7 psig, was proposed by the licensee. This change will comply with the requirements of Item II.E.4.2 of NUREG-0737 and is acceptable to the staff. The licensee has agreed to formally document the justification for the proposed setpoint value.

4. The feedwater isolation signal response time has been lowered from 5.35 seconds to 5.15 seconds. This change reflects the closure time for the main feedwater isolation valves based on operating experience. A valve closure time of 5.15 seconds was assumed in the peak containment pressure analysis; therefore, the staff finds this change acceptable.

10.0 ENVIRONMENTAL CONSIDERATION.

This amendment involve changes in the installation or use of a facility component located within the restricted area as defined in 10 CFR Part 20. The staff has determined that this amendment involves no significant increase in the amounts, and no significant change in the types, of any effluents that may be released offsite, and that there is no significant increase in individual or cumulative occupational radiation exposure. The Commission has previously issued a proposed finding that this amendment involves no significant hazards consideration and there has been no public comment on such finding. Accordingly, this amendment meets the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the issuance of this amendment.

11.0 CONCLUSION

We have concluded, based on the considerations discussed above, that: (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, and (2) such activities will be conducted in compliance with the Commission's regulations and the issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public.

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