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

September 14, 1992

Docket Nos. 50-413
and 50-414

Mr. M. S. Tuckman
Vice President, Catawba Site
Duke Power Company
4800 Concord Road
York, South Carolina 29745

Dear Mr. Tuckman:

SUBJECT: ISSUANCE OF AMENDMENTS - CATAWBA NUCLEAR STATION, UNITS 1 AND 2 (TACS M83173 AND M83174)

The Nuclear Regulatory Commission has issued the enclosed Amendment No. 101 to Facility Operating License NPF-35 and Amendment No. 95 to Facility Operating License NPF-52 for the Catawba Nuclear Station, Units 1 and 2. The amendments consist of changes to the Technical Specifications (TSs) in response to your application dated April 13, 1992, as supplemented July 8 and August 26, 1992. The August 26, 1992, letter also withdrew the proposed changes to TS Table 3.6-2a regarding isolation valve stroke times.

The amendments revise the TSs for Unit 1 Cycle 7 operation including revisions to reflect use of methodology developed by the Duke Power Company for accident and transient analysis, as well as other revisions.

A copy of the related Safety Evaluation is also enclosed. A Notice of Issuance will be included in the Commission's biweekly Federal Register notice.

Sincerely,

Robert Martin

Robert E. Martin, Project Manager
Project Directorate II-3
Division of Reactor Projects I/II
Office of Nuclear Reactor Regulation

Enclosures:
1. Amendment No. 101 to NPF-35
2. Amendment No. 95 to NPF-52
3. Safety Evaluation

cc w/enclosures:
See next page

Mr. M. S. Tuckman
Duke Power Company

Catawba Nuclear Station

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DATED: September 14, 1992

AMENDMENT NO. 101 TO FACILITY OPERATING LICENSE NPF-35 - Catawba Nuclear Station, Unit 1

AMENDMENT NO. 95 TO FACILITY OPERATING LICENSE NPF-52 - Catawba Nuclear Station, Unit 2

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

DUKE POWER COMPANY

NORTH CAROLINA ELECTRIC MEMBERSHIP CORPORATION

SALUDA RIVER ELECTRIC COOPERATIVE, INC.

DOCKET NO. 50-413

CATAWBA NUCLEAR STATION, UNIT 1

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 101
License No. NPF-35

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

   A. The application for amendment to the Catawba Nuclear Station, Unit 1 (the facility) Facility Operating License No. NPF-35 filed by the Duke Power Company, acting for itself, North Carolina Electric Membership Corporation and Saluda River Electric Cooperative, Inc. (licensees) dated April 13, 1992, as supplemented July 8 and August 26, 1992, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations as 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 set forth in 10 CFR Chapter I;

   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.

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PDR ADOCK 05000413
P PDR

2. Accordingly, the license is hereby amended by page changes to the Technical Specifications as indicated in the attachment to this license amendment, and Paragraph 2.C.(2) of Facility Operating License No. NPF-35 is hereby amended to read as follows:

   Technical Specifications

   The Technical Specifications contained in Appendix A, as revised through Amendment No. 101 , and the Environmental Protection Plan contained in Appendix B, both of which are attached hereto, are hereby incorporated into this license. Duke Power Company shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

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

FOR THE NUCLEAR REGULATORY COMMISSION

David B. Matthews, Director
Project Directorate II-3
Division of Reactor Projects-I/II
Office of Nuclear Reactor Regulation

Attachment:
Technical Specification
Changes

Date of Issuance: September 14, 1992

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

DUKE POWER COMPANY

NORTH CAROLINA MUNICIPAL POWER AGENCY NO. 1

PIEDMONT MUNICIPAL POWER AGENCY

DOCKET NO. 50-414

CATAWBA NUCLEAR STATION, UNIT 2

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 95
License No. NPF-52

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

   A. The application for amendment to the Catawba Nuclear Station, Unit 2 (the facility) Facility Operating License No. NPF-52 filed by the Duke Power Company, acting for itself, North Carolina Municipal Power Agency No. 1 and Piedmont Municipal Power Agency (licensees) dated April 13, 1992, as supplemented July 8 and August 26, 1992, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations as 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 set forth in 10 CFR Chapter I;

   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, the license is hereby amended by page changes to the Technical Specifications as indicated in the attachment to this license amendment, and Paragraph 2.C.(2) of Facility Operating License No. NPF-52 is hereby amended to read as follows:

   Technical Specifications

   The Technical Specifications contained in Appendix A, as revised through Amendment No. 95 , and the Environmental Protection Plan contained in Appendix B, both of which are attached hereto, are hereby incorporated into this license. Duke Power Company shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

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

FOR THE NUCLEAR REGULATORY COMMISSION

David B. Matthews, Director
Project Directorate II-3
Division of Reactor Projects-I/II
Office of Nuclear Reactor Regulation

Attachment:
Technical Specification Changes

Date of Issuance: September 14, 1992

ATTACHMENT TO LICENSE AMENDMENT NO. 101

FACILITY OPERATING LICENSE NO. NPF-35

DOCKET NO. 50-413

AND

TO LICENSE AMENDMENT NO. 95

FACILITY OPERATING LICENSE NO. NPF-52

DOCKET NO. 50-414

Replace the following pages of the Appendix "A" Technical Specifications with the enclosed pages. The revised pages are identified by Amendment number and contain vertical lines indicating the areas of change.

Remove Pages	Insert Pages
2-2	2-2
2-3	2-3
Table 2.2-1 For Unit 1	
2-4	A 2-4
2-5	A 2-5
2-6	A 2-6
2-7	A 2-7
2-8	A 2-8
2-9	A 2-9
2-10	A 2-10
Table 2.2-1 For Unit 2	
-	B 2-4
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-	B 2-8
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-	B 2-10
Bases	
B 2-1	B 2-1
B 2-2	B 2-2
B 2-3	B 2-3
B 2-4	B 2-4

Remove Pages	Insert Pages
Table 3.1-1	
3/4 1-16	3/4 1-16
Power Distribution Limits For Unit 1	
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3/4 A 2-6	3/4 A 2-6
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3/4 A 2-13	3/4 A 2-13
Table 3.3-1 For Unit 1	
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3/4 3-3	3/4 A 3-3
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3/4 3-5	3/4 A 3-5
3/4 3-6	3/4 A 3-6
3/4 3-7	3/4 A 3-7
3/4 3-8	3/4 A 3-8
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Table 3.3-1 For Unit 2	
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-	3/4 B 3-3
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-	3/4 B 3-5
-	3/4 B 3-6
-	3/4 B 3-7
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-	3/4 B 3-9
-	3/4 B 3-10
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-	3/4 B 3-12a
ESF Instrumentation	
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Remove Pages	Insert Pages
Table 3.3-4 For Unit 1	
3/4 3-27	3/4 A 3-27
3/4 3-28	3/4 A 3-28
3/4 3-29	3/4 A 3-29
3/4 3-30	3/4 A 3-30
3/4 3-31	3/4 A 3-31
3/4 3-32	3/4 A 3-32
3/4 3-33	3/4 A 3-33
3/4 3-34	3/4 A 3-34
3/4 3-35	3/4 A 3-35
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Table 3.3-4 For Unit 2	
-	3/4 B 3-27
-	3/4 B 3-28
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Table 3.3-5 For Unit 1	
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3/4 3-38	3/4 A 3-38
3/4 3-39	3/4 A 3-39
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Table 3.3-5 For Unit 2	
-	3/4 B 3-37
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-	3/4 B 3-39
-	3/4 B 3-40
Reactor Coolant System	
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3/4 4-8	3/4 4-8
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Administrative Controls	
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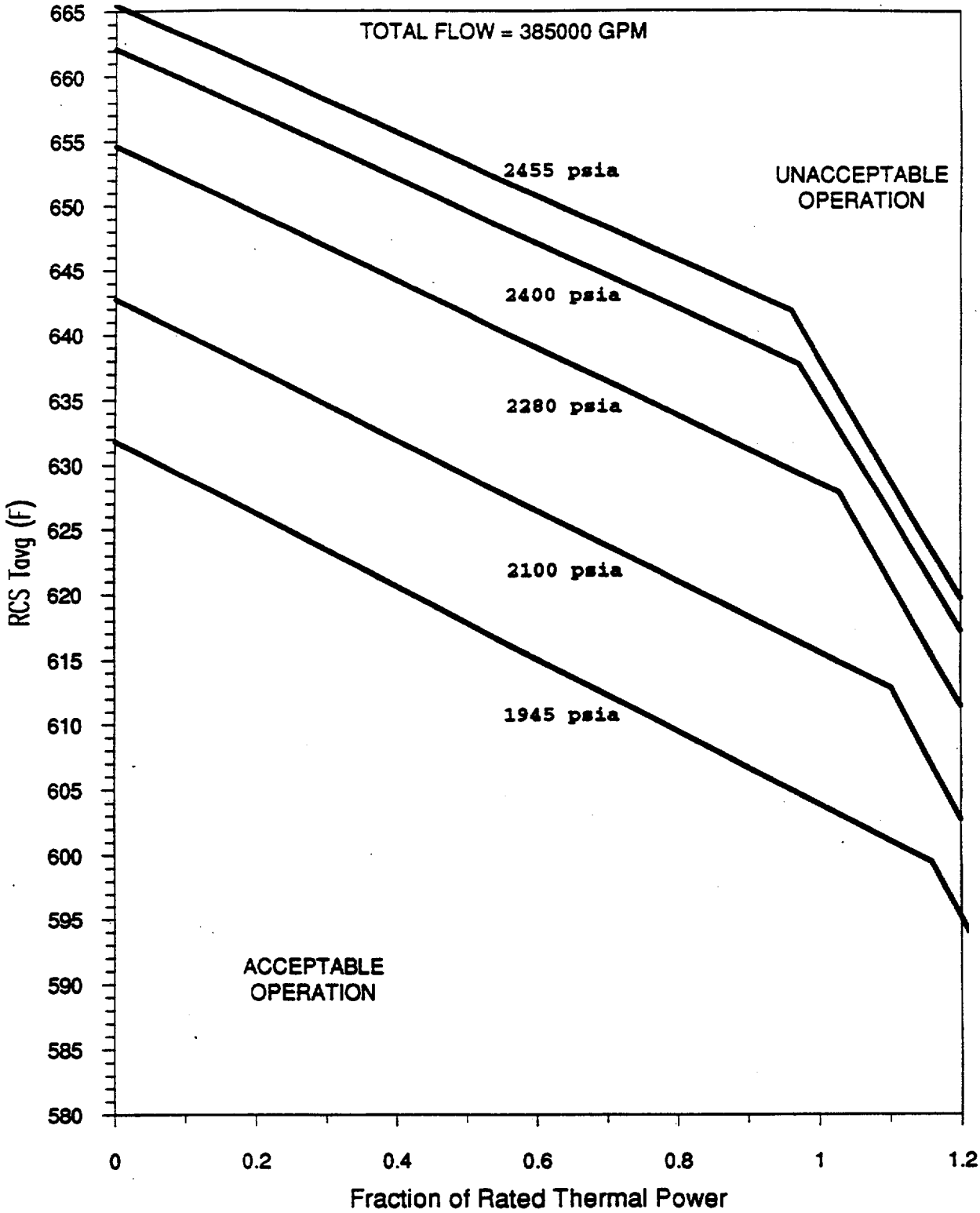

FIGURE 2.1-1a

REACTOR CORE SAFETY LIMITS - FOUR LOOPS IN OPERATION, UNIT 1

2.2 LIMITING SAFETY SYSTEM SETTINGS

REACTOR TRIP SYSTEM INSTRUMENTATION SETPOINTS

2.2.1 The Reactor Trip System Instrumentation and Interlocks 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:

a. With a Reactor Trip System Instrumentation or Interlock Setpoint less conservative than the value shown in the Trip Setpoint column but more conservative than the value shown in the Allowable Value Column of Table 2.2-1, adjust the Setpoint consistent with the Trip Setpoint value.

b. With the Reactor Trip System Instrumentation or Interlock 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 Setpoint adjusted consistent with the Trip Setpoint value.

TABLE 2.2.-1 FOR UNIT 1

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUE
1. Manual Reactor Trip	N.A.	N.A.
2. Power Range, Neutron Flux		
a. High Setpoint	≤109% of RTP*	≤110.9% of RTP*
b. Low Setpoint	≤25% of RTP*	≤27.1% of RTP*
3. Power Range, Neutron Flux, High Positive Rate	≤5% of RTP* with a time constant ≥ 2 seconds	≤6.3% of RTP* with a time constant ≥ 2 seconds
4. Intermediate Range, Neutron Flux	≤25% of RTP*	≤31% of RTP*
5. Source Range, Neutron Flux	$\leq 10^5$ cps	$\leq 1.4 \times 10^5$ cps
6. Overtemperature ΔT	See Note 1	See Note 2
7. Overpower ΔT	See Note 3	See Note 4
8. Pressurizer Pressure-Low	≥1945 psig	≥1938 psig***
9. Pressurizer Pressure-High	≤2385 psig	≤2399 psig
10. Pressurizer Water Level-High	≤92% of instrument span	≤93.8% of instrument span
11. Reactor Coolant Flow-Low	≥90% of loop minimum measured flow**	≥88.9% of loop minimum measured flow**

*RTP = RATED THERMAL POWER

**Loop minimum measured flow = 96,900 gpm (Unit 2), 96,250 gpm (Unit 1)

***Time constants utilized in the lead-lag controller for Pressurizer Pressure-Low are 2 seconds for lead and 1 second for lag. Channel calibration shall ensure that these time constants are adjusted to these values.

TABLE 2.2-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUE
12. Steam Generator Water Level Low-Low		
a. Unit 1	≥17% of span from 0% to 30% RTP* increasing linearly to ≥ 40.0% of span from 30% to 100% RTP*	≥15.3% of span from 0% to 30% RTP* increasing linearly to ≥38.3% of span from 30% to 100% RTP*
b. Unit 2	≥36.8% of narrow range span	≥35.1% of narrow range span
13. Undervoltage - Reactor Coolant Pumps	≥77% of bus voltage (5082 volts) with a 0.7s response time	≥76% (5016 volts)
14. Underfrequency - Reactor Coolant Pumps	≥56.4 Hz with a 0.2s response time	≥55.9 Hz
15. Turbine Trip		
a. Stop Valve EH Pressure Low	≥550 psig	≥500 psig
b. Turbine Stop Valve Closure	≥1% open	≥1% open
16. Safety Injection Input from ESF	N.A.	N.A.

*RTP = RATED THERMAL POWER

TABLE 2.2-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUE
17. Reactor Trip System Interlocks		
a. Intermediate Range Neutron Flux, P-6	$\geq 1 \times 10^{-10}$ amps	$\geq 6 \times 10^{-11}$ amps
b. Low Power Reactor Trips Block, P-7		
1) P-10 input	$\leq$10% of RTP*	$\leq$12.2% of RTP*
2) P-13 input	$\leq$10% RTP* Turbine Impulse Pressure Equivalent	$\leq$12.2% RTP* Turbine Impulse Pressure Equivalent
c. Power Range Neutron Flux, P-8	$\leq$48% of RTP*	$\leq$50.2% of RTP*
d. Power Range Neutron Flux, P-9	$\leq$69% of RTP*	$\leq$70% of RTP*
e. Power Range Neutron Flux, P-10	$\geq$10% of RTP*	$\geq$7.8% of RTP*
f. Power Range Neutron Flux, Not P-10	$\leq$10% of RTP*	$\leq$12.2% of RTP*
g. Turbine Impulse Chamber Pressure, P-13	$\leq$10% RTP* Turbine Impulse Pressure Equivalent	$\leq$12.2% RTP* Turbine Impulse Pressure Equivalent
18. Reactor Trip Breakers	N.A.	N.A.
19. Automatic Trip and Interlock Logic	N.A.	N.A.

*RTP = RATED THERMAL POWER

TABLE 2.2-1 (Continued)
TABLE NOTATIONS

NOTE 1: OVERTEMPERATURE ΔT

$$\Delta T \frac{(1 + \tau_1 S)}{(1 + \tau_2 S)} \left(\frac{1}{1 + \tau_3 S}\right) \leq \Delta T_o \left\{K_1 - K_2 \frac{(1 + \tau_4 S)}{(1 + \tau_5 S)} \left[T \left(\frac{1}{1 + \tau_6 S}\right) - T'\right] + K_3(P - P') - f_1(\Delta I)\right\}$$

Where:

ΔT	=	Measured ΔT by Loop Narrow Range RTDs;
$\frac{1 + \tau_1 S}{1 + \tau_2 S}$	=	Lead-lag compensator on measured ΔT;
τ_1, τ_2	=	Time constants utilized in lead-lag compensator for ΔT, τ_1 = 12 s, τ_2 = 3 s;
$\frac{1}{1 + \tau_3 S}$	=	Lag compensator on measured ΔT;
τ_3	=	Time constant utilized in the lag compensator for ΔT, τ_3 = 0;
ΔT_o	=	Indicated ΔT at RATED THERMAL POWER;
K_1	=	1.1953
K_2	=	0.03163/°F
$\frac{1 + \tau_4 S}{1 + \tau_5 S}$	=	The function generated by the lead-lag compensator for T_{avg} dynamic compensation;
τ_4, τ_5	=	Time constants utilized in the lead-lag compensator for T_{avg}, τ_4 = 22 s, τ_5 = 4 s;
T	=	Average temperature, °F;
$\frac{1}{1 + \tau_6 S}$	=	Lag compensator on measured T_{avg};
τ_6	=	Time constant utilized in the measured T_{avg} lag compensator, τ_6 = 0;

TABLE 2.2-1 (Continued)
TABLE NOTATIONS (Continued)

NOTE 1: (Continued)

T' $\leq$ 590.8°F (Nominal T_{avg} allowed by Safety Analysis);

K_3 = 0.001414;

P = Pressurizer pressure, psig;

P' = 2235 psig (Nominal RCS operating pressure);

S = Laplace transform operator, s^{-1};

and $f_1(\Delta I)$ is a function of the indicated difference between top and bottom detectors of the power-range neutron ion chambers; with gains to be selected based on measured instrument response during plant STARTUP tests such that:

(i) For $q_t - q_b$ between -39.9% and +3.0%, $f_1(\Delta I) = 0$, where q_t and q_b are percent RATED THERMAL POWER in the top and bottom halves of the core respectively, and $q_t + q_b$ is total THERMAL POWER in percent of RATED THERMAL POWER;

(ii) For each percent ΔI that the magnitude of $q_t - q_b$ is more negative than -39.9%, the ΔT Trip Setpoint shall be automatically reduced by 3.910% of ΔT_o; and

(iii) For each percent ΔI that the magnitude of $q_t - q_b$ is more positive than +3.0%, the ΔT Trip Setpoint shall be automatically reduced by 2.316% of ΔT_o.

NOTE 2: The channel's maximum Trip Setpoint shall not exceed its computed Trip Setpoint by more than 3.0%.

TABLE 2.2-1 (Continued)
TABLE NOTATIONS (Continued)

NOTE 3: OVERPOWER ΔT

$$\Delta T \frac{(1 + \tau_1 S)}{(1 + \tau_2 S)} \frac{(1)}{(1 + \tau_3 S)} \leq \Delta T_0 \{K_4 - K_5 \frac{(\tau_7 S)}{(1 + \tau_7 S)} \frac{(1)}{(1 + \tau_6 S)} T - K_6 [T \frac{(1)}{(1 + \tau_6 S)} - T''] - f_2(\Delta I)\}$$

Where:

ΔT = As defined in Note 1,

$\frac{1 + \tau_1 S}{1 + \tau_2 S}$ = As defined in Note 1,

τ_1, τ_2 = As defined in Note 1,

$\frac{1}{1 + \tau_3 S}$ = As defined in Note 1,

τ_3 = As defined in Note 1,

ΔT_0 = As defined in Note 1,

K_4 = 1.0819

K_5 = 0.02/°F for increasing average temperature and 0 for decreasing average temperature,

$\frac{\tau_7 S}{1 + \tau_7 S}$ = The function generated by the rate-lag controller for T_{avg} dynamic compensation,

τ_7 = Time constant utilized in the rate-lag controller for T_{avg}, τ_7 = 10 s,

$\frac{1}{1 + \tau_6 S}$ = As defined in Note 1,

τ_6 = As defined in Note 1,

TABLE 2.2-1 (Continued)
TABLE NOTATIONS (Continued)

NOTE 3: (Continued)

K_6 = 0.001291/°F for T > 590.8°F and K_6 = 0 for T ≤ 590.8°F,

T = As defined in Note 1,

T" = Indicated T_{avg} at RATED THERMAL POWER (Calibration temperature for ΔT instrumentation, ≤ 590.8°F),

S = As defined in Note 1,

and f_2 (ΔI) is a function of the indicated differences between top and bottom detectors of the power-range neutron ion chambers; with gains to be selected based on measured instrument response during plant startup tests such that:

(i) for $q_t - q_b$ between -35% and +35% ΔI; f_2 (ΔI) = 0, where q_t and q_b are percent RATED THERMAL POWER in the top and bottom halves of the core respectively, and $q_t + q_b$ is total THERMAL POWER in percent of RATED THERMAL POWER;

(ii) for each percent ΔI that the magnitude of $q_t - q_b$ is more negative than -35% ΔI, the ΔT Trip Setpoint shall be automatically reduced by 7.0% of ΔT_o; and

(iii) for each percent ΔI that magnitude of $q_t - q_b$ is more positive than +35% ΔI, the ΔT Trip Setpoint shall be automatically reduced by 7.0% of ΔT_o.

NOTE 4: The channel's maximum Trip Setpoint shall not exceed its computed Trip Setpoint by more than 2.8%.

TABLE 2.2.-1 FOR UNIT 2

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUE
1. Manual Reactor Trip	N.A.	N.A.
2. Power Range, Neutron Flux		
a. High Setpoint	≤109% of RTP*	≤110.9% of RTP*
b. Low Setpoint	≤25% of RTP*	≤27.1% of RTP*
3. Power Range, Neutron Flux, High Positive Rate	≤5% of RTP* with a time constant ≥ 2 seconds	≤6.3% of RTP* with a time constant ≥ 2 seconds
4. Power Range, Neutron Flux High Negative Rate	≤5% of RTP* with a time constant ≥2 seconds	≤6.3% of RTP* with a time constant ≥2 seconds
5. Intermediate Range, Neutron Flux	≤25% of RTP*	≤31% of RTP*
6. Source Range, Neutron Flux	$\leq 10^5$ cps	$\leq 1.4 \times 10^5$ cps
7. Overtemperature ΔT	See Note 1	See Note 2
8. Overpower ΔT	See Note 3	See Note 4
9. Pressurizer Pressure-Low	≥1945 psig	≥1938 psig***
10. Pressurizer Pressure-High	≤2385 psig	≤2399 psig
11. Pressurizer Water Level-High	≤92% of instrument span	≤93.8% of instrument span
12. Reactor Coolant Flow-Low	≥90% of loop minimum measured flow**	≥88.9% of loop minimum measured flow**

*RTP = RATED THERMAL POWER
**Loop minimum measured flow = 96,900 gpm (Unit 2), 96,250 gpm (Unit 1)
***Time constants utilized in the lead-lag controller for Pressurizer Pressure-Low are 2 seconds for lead and 1 second for lag. Channel calibration shall ensure that these time constants are adjusted to these values.

TABLE 2.2-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUE
13. Steam Generator Water Level Low-Low		
a. Unit 1	≥17% of span from 0% to 30% RTP* increasing linearly to ≥ 40.0% of span from 30% to 100% RTP*	≥15.3% of span from 0% to 30% RTP* increasing linearly to ≥38.3% of span from 30% to 100% RTP*
b. Unit 2	≥36.8% of narrow range span	≥35.1% of narrow range span
14. Undervoltage - Reactor Coolant Pumps	≥77% of bus voltage (5082 volts) with a 0.7s response time	≥76% (5016 volts)
15. Underfrequency - Reactor Coolant Pumps	≥56.4 Hz with a 0.2s response time	≥55.9 Hz
16. Turbine Trip		
a. Stop Valve EH Pressure Low	≥550 psig	≥500 psig
b. Turbine Stop Valve Closure	≥1% open	≥1% open
17. Safety Injection Input from ESF	N.A.	N.A.

*RTP = RATED THERMAL POWER

TABLE 2.2-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUE
18. Reactor Trip System Interlocks		
a. Intermediate Range Neutron Flux, P-6	$\geq 1 \times 10^{-10}$ amps	$\geq 6 \times 10^{-11}$ amps
b. Low Power Reactor Trips Block, P-7		
1) P-10 input	$\leq$10% of RTP*	$\leq$12.2% of RTP*
2) P-13 input	$\leq$10% RTP* Turbine Impulse Pressure Equivalent	$\leq$12.2% RTP* Turbine Impulse Pressure Equivalent
c. Power Range Neutron Flux, P-8	$\leq$48% of RTP*	$\leq$50.2% of RTP*
d. Power Range Neutron Flux, P-9	$\leq$69% of RTP*	$\leq$70% of RTP*
e. Power Range Neutron Flux, P-10	$\geq$10% of RTP*	$\geq$7.8% of RTP*
f. Power Range Neutron Flux, Not P-10	$\leq$10% of RTP*	$\leq$12.2% of RTP*
g. Turbine Impulse Chamber Pressure, P-13	$\leq$10% RTP* Turbine Impulse Pressure Equivalent	$\leq$12.2% RTP* Turbine Impulse Pressure Equivalent
19. Reactor Trip Breakers	N.A	N.A.
20. Automatic Trip and Interlock Logic	N.A.	N.A.

*RTP = RATED THERMAL POWER

TABLE 2.2-1 (Continued)
TABLE NOTATIONS

NOTE 1: OVERTEMPERATURE ΔT

$$\Delta T \frac{(1 + \tau_1 S)}{(1 + \tau_2 S)} \left(\frac{1}{1 + \tau_3 S}\right) \leq \Delta T_o \left\{K_1 - K_2 \frac{(1 + \tau_4 S)}{(1 + \tau_5 S)} \left[T \left(\frac{1}{1 + \tau_6 S}\right) - T'\right] + K_3(P - P') - f_1(\Delta I)\right\}$$

Where:

ΔT	=	Measured ΔT by Loop Narrow Range RTDs;
$\frac{1 + \tau_1 S}{1 + \tau_2 S}$	=	Lead-lag compensator on measured ΔT;
τ_1, τ_2	=	Time constants utilized in lead-lag compensator for ΔT, τ_1 = 12 s, τ_2 = 3 s;
$\frac{1}{1 + \tau_3 S}$	=	Lag compensator on measured ΔT;
τ_3	=	Time constant utilized in the lag compensator for ΔT, τ_3 = 0;
ΔT_o	=	Indicated ΔT at RATED THERMAL POWER;
K_1	=	1.38;
K_2	=	0.02401/°F;
$\frac{1 + \tau_4 S}{1 + \tau_5 S}$	=	The function generated by the lead-lag compensator for T_{avg} dynamic compensation;
τ_4, τ_5	=	Time constants utilized in the lead-lag compensator for T_{avg}, τ_4 = 22 s, τ_5 = 4 s;
T	=	Average temperature, °F;
$\frac{1}{1 + \tau_6 S}$	=	Lag compensator on measured T_{avg};
τ_6	=	Time constant utilized in the measured T_{avg} lag compensator, τ_6 = 0;

TABLE 2.2-1 (Continued)
TABLE NOTATIONS (Continued)

NOTE 1: (Continued)

T'	$\leq$	590.8°F (Nominal T_{avg} allowed by Safety Analysis);
K_3	=	0.001189;
P	=	Pressurizer pressure, psig;
P'	=	2235 psig (Nominal RCS operating pressure);
S	=	Laplace transform operator, s^{-1};

and $f_1(\Delta I)$ is a function of the indicated difference between top and bottom detectors of the power-range neutron ion chambers; with gains to be selected based on measured instrument response during plant STARTUP tests such that:

(i) For $q_t - q_b$ between -22.5% and -6.5%, $f_1(\Delta I) = 0$, where q_t and q_b are percent RATED THERMAL POWER in the top and bottom halves of the core respectively, and $q_t + q_b$ is total THERMAL POWER in percent of RATED THERMAL POWER;

(ii) For each percent ΔI that the magnitude of $q_t - q_b$ is more negative than -22.5%, the ΔT Trip Setpoint shall be automatically reduced by 3.151% of ΔT_o; and

(iii) For each percent ΔI that the magnitude of $q_t - q_b$ is more positive than -6.5%, the ΔT Trip Setpoint shall be automatically reduced by 2.414% of ΔT_o.

NOTE 2: The channel's maximum Trip Setpoint shall not exceed its computed Trip Setpoint by more than 1.3%.

TABLE 2.2-1 (Continued)
TABLE NOTATIONS (Continued)

NOTE 3: OVERPOWER ΔT

$$\Delta T \frac{(1 + \tau_1 S)}{(1 + \tau_2 S)} \left(\frac{1}{(1 + \tau_3 S)}\right) \leq \Delta T_o \left\{K_4 - K_5 \left(\frac{\tau_7 S}{(1 + \tau_7 S)}\right) \left(\frac{1}{(1 + \tau_6 S)}\right) T - K_6 \left[T \left(\frac{1}{(1 + \tau_6 S)}\right) - T''\right] - f_2(\Delta I)\right\}$$

Where: ΔT = As defined in Note 1,

$\frac{1 + \tau_1 S}{1 + \tau_2 S}$ = As defined in Note 1,

τ_1, τ_2 = As defined in Note 1,

$\frac{1}{1 + \tau_3 S}$ = As defined in Note 1,

τ_3 = As defined in Note 1,

ΔT_o = As defined in Note 1,

K_4 = 1.0704,

K_5 = 0.02/°F for increasing average temperature and 0 for decreasing average temperature,

$\frac{\tau_7 S}{1 + \tau_7 S}$ = The function generated by the rate-lag controller for T_{avg} dynamic compensation,

τ_7 = Time constant utilized in the rate-lag controller for T_{avg}, τ_7 = 10 s,

$\frac{1}{1 + \tau_6 S}$ = As defined in Note 1,

τ_6 = As defined in Note 1,

TABLE 2.2-1 (Continued)
TABLE NOTATIONS (Continued)

NOTE 3: (Continued)

K_6	=	0.001707/°F or T > 590.8°F and K_6 = 0 for T $\leq$ 590.8°F,
T	=	As defined in Note 1,
T"	=	Indicated T_{avg} at RATED THERMAL POWER (Calibration temperature for ΔT instrumentation, $\leq$ 590.8°F),
S	=	As defined in Note 1, and
$f_2(\Delta I)$	=	0 for all ΔI.

NOTE 4: The channel's maximum Trip Setpoint shall not exceed its computed Trip Setpoint by more than 2.8%.

2.1.1 REACTOR CORE (FOR UNIT 1)

The restrictions of this Safety Limit prevent overheating of the fuel and possible cladding perforation which would result in the release of fission products to the reactor coolant. 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 BWCMV correlation. The BWCMV DNB correlation has been developed to predict the DNB flux and the location of DNB for axially uniform and nonuniform heat flux distributions. The local DNB heat flux ratio, (DNBR), is defined as the ratio of the heat flux that would cause DNB at a particular core location to the local heat flux, and is indicative of the margin to DNB.

The DNB design basis is as follows: there must be at least a 95% probability that the minimum DNBR of the limiting rod during Condition I and II events is greater than or equal to the DNBR limit of the DNB correlation being used (the BWCMV correlation in this application). The correlation DNBR limit is established based on the entire applicable experimental data set such that there is a 95% probability with 95% confidence that DNB will not occur when the minimum DNBR is at the DNBR limit.

In meeting this design basis, uncertainties in plant operating parameters, nuclear and thermal parameters, and fuel fabrication parameters, and the BWCMV DNB correlation are considered statistically such that there is at least a 95% confidence that the minimum DNBR for the limited rod is greater than or equal to the DNBR limit. The uncertainties in the above parameters are used to determine the plant DNBR uncertainty. This DNBR uncertainty is used to establish a design DNBR value which must be met in plant safety analyses using values of input parameters without uncertainties.

The curves of Figure 2.1-1 show the loci of points of THERMAL POWER, Reactor Coolant System pressure and average temperature below which the calculated DNBR is no less than the design DNBR value, or the average enthalpy at the vessel exit is less than the enthalpy of saturated liquid.

These curves are based on a nuclear enthalpy rise hot channel factor, $F^N_{\Delta H}$, of 1.50 and a reference cosine with a peak of 1.55.
An allowance is included for an increase in $F^N_{\Delta H}$ at reduced power based on the expression:

$$F^N_{\Delta H} = 1.50\ [1 + 1/RRH\ (1-P)]$$

Where P is the fraction of RATED THERMAL POWER.
RRH is given in the COLR.

These limiting heat flux conditions are higher than those calculated for the range of all control rods fully withdrawn to the maximum allowable control rod insertion assuming the axial power imbalance is within the limits of the f_1 (ΔI) function of the Overtemperature ΔT trip. When the axial power imbalance is not within the tolerance, the axial power imbalance effect on the Overtemperature ΔT trips will reduce the Setpoints to provide protection consistent with core Safety Limits.

2.1.1 REACTOR CORE (FOR UNIT 2)

The restrictions of this Safety Limit prevent overheating of the fuel and possible cladding perforation which would result in the release of fission products to the reactor coolant. 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 WRB-1 correlation. The WRB-1 DNB correlation has been developed to predict the DNB flux and the location of DNB for axially uniform and nonuniform heat flux distributions. The local DNB heat flux ratio, (DNBR), is defined as the ratio of the heat flux that would cause DNB at a particular core location to the local heat flux, and is indicative of the margin to DNB.

The DNB design basis is as follows: there must be at least a 95% probability that the minimum DNBR of the limiting rod during Condition I and II events is greater than or equal to the DNBR limit of the DNB correlation being used (the WRB-1 correlation in this application). The correlation DNBR limit is established based on the entire applicable experimental data set such that there is a 95% probability with 95% confidence that DNB will not occur when the minimum DNBR is at the DNBR limit.

2.2.1 REACTOR TRIP SYSTEM INSTRUMENTATION SETPOINTS

The Reactor Trip Setpoint Limits specified in Table 2.2-1 are the nominal values at which the Reactor trips are set for each functional unit. The Trip Setpoints have been selected to ensure that the 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. The Setpoint for a Reactor Trip System or interlock function is considered to be adjusted consistent with the nominal value when the "as measured" Setpoint is within the band allowed for calibration accuracy.

To accommodate the instrument drift assumed to occur between operational tests and the accuracy to which Setpoints can be measured and calibrated, Allowable Values for the Reactor Trip Setpoints have been specified in Table 2.2-1. Operation with Setpoints less conservative than the Trip Setpoint but within the Allowable Value is acceptable since an allowance has been made in the safety analysis to accommodate this error.

The methodology to derive the Trip Setpoints is based upon combining all of the uncertainties in the channels. Inherent to the determination of the Trip Setpoints are the magnitudes of these channel uncertainties. Sensors and other instrumentation utilized in these channels are expected to be capable of operating within the allowances of these uncertainty magnitudes. Rack drift in excess of the Allowable Value exhibits the behavior that the rack has not met its allowance. Being that there is a small statistical chance that this will happen, an infrequent excessive drift is expected. Rack or sensor drift, in excess of the allowance that is more than occasional, may be indicative of more serious problems and should warrant further investigation.

REACTOR TRIP SYSTEM INSTRUMENTATION SETPOINTS (Continued)

The various Reactor trip circuits automatically open the Reactor trip breakers whenever a condition monitored by the Reactor Trip System reaches a preset or calculated level. In addition to redundant channels and trains, the design approach provides a Reactor Trip System which monitors numerous system variables, therefore providing Trip System functional diversity. The functional capability at the specified trip setting is required for those anticipatory or diverse Reactor trips for which no direct credit was assumed in the accident analysis to enhance the overall reliability of the Reactor Trip System. The Reactor Trip System initiates a Turbine trip signal whenever Reactor trip is initiated. This prevents the reactivity insertion that would otherwise result from excessive Reactor Coolant System cooldown and thus avoids unnecessary actuation of the Engineered Safety Features Actuation System.

Manual Reactor Trip

The Reactor Trip System includes manual Reactor trip capability.

Power Range, Neutron Flux

In each of the Power Range Neutron Flux channels there are two independent bistables, each with its own trip setting used for a High and Low Range trip setting. The Low Setpoint trip provides protection during subcritical and low power operations to mitigate the consequences of a power excursion beginning from low power, and the High Setpoint trip provides protection during power operations to mitigate the consequences of a reactivity excursion from all power levels.

The Low Setpoint trip may be manually blocked above P-10 (a power level of approximately 10% of RATED THERMAL POWER) and is automatically reinstated below the P-10 Setpoint.

Power Range, Neutron Flux, High Rates

The Power Range Positive Rate trip provides protection against rapid flux increases which are characteristic of a rupture of a control rod drive housing. Specifically, this trip complements the Power Range Neutron Flux High and Low trips to ensure that the criteria are met for all rod ejection accidents.

The Power Range Negative Rate trip provides protection for control rod drop accidents. At high power a rod drop accident could cause local flux peaking which could cause an unconservative local DNBR to exist. The Power Range Negative Rate trip will prevent this from occurring by tripping the reactor. No credit is taken for operation of the Power Range Negative Rate trip for those control rod drop accidents for which DNBRs will be greater than the applicable design limit DNBR value for each fuel type.

The Power Range Negative Rate Trip has been deleted for Unit 1.

TABLE 3.1-1

ACCIDENT ANALYSES REQUIRING REEVALUATION IN THE EVENT OF AN INOPERABLE FULL-LENGTH ROD

Rod Cluster Control Assembly Insertion Characteristics

Rod Cluster Control Assembly Misoperation

Loss of Reactor Coolant from Small Ruptured Pipes or from Cracks in Large Pipes Which Actuates the Emergency Core Cooling System

Major Secondary Coolant System Pipe Rupture

Rupture of a Control Rod Drive Mechanism Housing (Rod Cluster Control Assembly Ejection)

POWER DISTRIBUTION LIMITS

SURVEILLANCE REQUIREMENTS (Continued)

(a) Within 15 minutes:

(1) Control the AFD to within new AFD limits that are determined by:

$$(\text{AFD Limit})^{\text{reduced}}_{\text{negative}} = (\text{AFD Limit})^{\text{COLR}^{(3)}}_{\text{negative}} + [\text{Margin}^{\text{min}}_{\text{OP}}] \text{ absolute value}$$

$$(\text{AFD Limit})^{\text{reduced}}_{\text{positive}} = (\text{AFD Limit})^{\text{COLR}^{(3)}}_{\text{positive}} - [\text{Margin}^{\text{min}}_{\text{OP}}] \text{ absolute value}$$

where $\text{Margin}^{\text{min}}_{\text{OP}}$ is the minimum margin from 4.2.2.2.c.1, and

(2) Within 8 hours, reset the AFD alarm setpoints to the modified limits of 4.2.2.2.c.2.a, or

(b) Comply with the ACTION requirements of Specification 3.2.2, treating the margin violation in 4.2.2.2.c.1 above as the amount by which F_Q^{MA} is exceeding its limit.

3. Find the minimum RPS Margin of all locations examined in 4.2.2.2.c.1 above. If any margin is less than zero, then the following action shall be taken:

Within 72 hours, reduce the K_1 value for OTΔT by:

$$K_1 \text{ adjusted} = K_1^{(4)} - [\text{KSLOPE}^{(3)} \times \text{Margin}^{\text{min}}_{\text{RPS}}]\text{absolute value}$$

where $\text{MARGIN}^{\text{min}}_{\text{RPS}}$ is the minimum margin from 4.2.2.2.c.1.

(3) Defined and specified in the COLR per Specification 6.9.1.9.

(4) K_1 value from Table 2.2-1.

d. Extrapolating(5) at least two measurements to 31 Effective Full Power Days beyond the most recent measurement and if:

$$(F_Q^M(X,Y,Z))\ \text{(extrapolated)} \geq (F_Q^L(X,Y,Z))^{OP}\ \text{(extrapolated)},\ \text{and}$$

$$\frac{(F_Q^M(X,Y,Z))\ \text{(extrapolated)}}{(F_Q^L(X,Y,Z))^{OP}\ \text{(extrapolated)}} > \frac{(F_Q^M(X,Y,Z))}{(F_Q^L(X,Y,Z))^{OP}}$$

or

$$(F_Q^M(X,Y,Z))\ \text{(extrapolated)} \geq (F_Q^L(X,Y,Z))^{RPS}\ \text{(extrapolated)},\ \text{and}$$

$$\frac{(F_Q^M(X,Y,Z))\ \text{(extrapolated)}}{(F_Q^L(X,Y,Z))^{RPS}\ \text{(extrapolated)}} > \frac{(F_Q^M(X,Y,Z))}{(F_Q^L(X,Y,Z))^{RPS}}$$

either of the following actions shall be taken:

1. $F_Q^M(X,Y,Z)$ shall be increased by 2 percent over that specified in 4.2.2.2.a, and the calculations of 4.2.2.2.c repeated, or
2. A movable incore detector power distribution map shall be obtained, and the calculations of 4.2.2.2.c.1 shall be performed no later than the time at which the margin in 4.2.2.2.c.1 is extrapolated to be equal to zero.

e. The limits in Specifications 4.2.2.2.c and 4.2.2.2.d are not applicable in the following core plane regions as measured in percent of core height from the bottom of the fuel:

1. Lower core region from 0 to 15%, inclusive.
2. Upper core region from 85 to 100%, inclusive.

4.2.2.3 When a full core power distribution map is taken for reasons other than meeting the requirements of Specification 4.2.2.2, an overall $F_Q^M(X,Y,Z)$ shall be determined, then increased by 3% to account for manufacturing tolerances, further increased by 5% to account for measurement uncertainty, and further increased by the radial-local peaking factor to obtain a maximum local peak. This value shall be compared to the limit in Specification 3.2.2.

(5) Extrapolation of F_Q^M for the initial flux map taken after reaching equilibrium conditions is not required since the initial flux map extablishes the baseline measurement for future trending. Also, extrapolation of F_Q^M limits are not valid for core locations that were previously rodded, or for core locations that were previously within ±2% of the core height about the demand position of the rod tip.

POWER DISTRIBUTION LIMITS

3/4.2.3 NUCLEAR ENTHALPY RISE HOT CHANNEL FACTOR $F\Delta H(X,Y)$

LIMITING CONDITION FOR OPERATION

3.2.3 $F_{\Delta H}(X,Y)$ shall be limited by imposing the following relationship:

$$F\Delta H^{M}(X,Y) \leq [F\Delta H^{L}(X,Y]^{LCO}$$

Where: $F\Delta H^{M}(X,Y)$ = the measured radial peak.

$[F\Delta H^{L}(X,Y)]^{LCO}$ = the maximum allowable radial peak as defined in the CORE OPERATING LIMITS REPORT (COLR).

APPLICABILITY: MODE 1. (UNIT 1)

ACTION:

With $F_{\Delta H}(X,Y)$ exceeding its limit:

a. Within 2 hours, reduce the allowable THERMAL POWER from RATED THERMAL POWER at least RRH%[1] for each 1% that $F\Delta H^{M}(X,Y)$ exceeds the limit, and

b. Within 6 hours either:

   1. Restore $F\Delta H^{M}(X,Y)$ to within the limit of Specification 3.2.3 for RATED THERMAL POWER, or

   2. Reduce the Power Range Neutron Flux-High Trip Setpoint in Table 2.2-1 at least RRH% for each 1% that $F\Delta H^{M}(X,Y)$ exceeds that limit, and

c. Within 72 hours of initially being outside the limit of Specification 3.2.3, either:

   1. Restore $F\Delta H^{M}(X,Y)$ to within the limit of Specification 3.2.3 for RATED THERMAL POWER, or

   2. Perform the following actions:

      (a) Reduce the OTΔT K_1 term in Table 2.2-1 by at least TRH[2] for each 1% that $F\Delta H^{M}(X,Y)$ exceeds the limit, and

      (b) Verify through incore mapping that $F\Delta H^{M}(X,Y)$ is restored to within the limit for the reduced THERMAL POWER allowed by ACTION a, or reduce THERMAL POWER to less than 5% of RATED THERMAL POWER within the next 2 hours.

---

[1] RRH is the amount of THERMAL POWER reduction required to compensate for each 1% that $F\Delta H^{M}(X,Y)$ exceeds the limits of Specification 3.2.3 provided in the COLR per Specification 6.9.1.9.

[2] TRH is the amount of OTΔT K_1 setpoint reduction required to compensate for each 1% that $F\Delta H^{M}(X,Y)$ exceeds the limit of Specification 3.2.3, provided in the COLR per Specification 6.9.1.9.

POWER DISTRIBUTION LIMITS

LIMITING CONDITION FOR OPERATION

ACTION (Continued)

d. Identify and correct the cause of the out-of-limit condition prior to increasing THERMAL POWER above the reduced THERMAL POWER limit required by ACTION a. and/or c.2., above; subsequent POWER OPERATION may proceed provided that $F\Delta H^M(X,Y)$ is demonstrated, through incore flux mapping, to be within the limit specified in the COLR prior to exceeding the following THERMAL POWER levels:

1) 50% of RATED THERMAL POWER,

2) 75% of RATED THERMAL POWER, and

3) Within 24 hours of attaining greater than or equal to 95% of RATED THERMAL POWER.

SURVEILLANCE REQUIREMENTS

4.2.3.1 The provisions of Specification 4.0.4 are not applicable.

4.2.3.2 $F\Delta H^M(X,Y)$ shall be evaluated to determine whether $F_{\Delta H}(X,Y)$ is within its limit by:

a. Using the movable incore detectors to obtain a power distribution map at any THERMAL POWER greater than 5% of RATED THERMAL POWER.

b. Measuring $F\Delta H^M(X,Y)$ according to the following schedule:

1. Upon reaching equilibrium conditions after exceeding by 10% or more of RATED THERMAL POWER, the THERMAL POWER at which $F\Delta H^M(X,Y)$ was last determined(3), or

2. At least once per 31 Effective Full Power Days, or

3. At each time the QUADRANT POWER TILT RATIO indicated by the excore detectors is normalized using incore detector measurements.

c. Performing the following calculations:

1. For each location, calculate the % margin to the maximum allowable design as follows:

$$\%F_{\Delta H}\ \text{Margin} = 1 - \left[\frac{F\Delta H^M(X,Y)}{[F\Delta H^L(X,Y)]^{SURV}}\right] \times 100\%$$

Where $[F\Delta H^L(X,Y)]^{SURV}$ is the design peaking limit defined in the COLR.

No additional uncertainties are required for $F\Delta H^M(X,Y)$, because $[F\Delta H^L(X,Y)]^{SURV}$, includes uncertainties.

(3) During power escalation at the beginning of each cycle, THERMAL POWER may be increased until a power level for extended operation has been achieved and a power distribution map obtained.

POWER DISTRIBUTION LIMITS

3/4.2.5 DNB PARAMETERS

LIMITING CONDITION FOR OPERATION

3.2.5 The following DNB related parameters shall be maintained within the limits shown on Table 3.2-1:

a. Reactor Coolant System T_{avg},

b. Pressurizer Pressure,

c. Reactor Coolant System Total Flow Rate.

APPLICABILITY: MODE 1. (Unit 1)

ACTION:

a. With either of the parameters identified in 3.2.5a. and b. above exceeding its limit, restore the parameter to within its limit within 2 hours or reduce THERMAL POWER to less than 5% of RATED THERMAL POWER within the next 4 hours.

b. With the combination of Reactor Coolant System total flow rate and THERMAL POWER within the region of restricted operation specified on Figure 3.2-1, within 6 hours reduce the Power Range Neutron Flux-High Trip Setpoint to below the nominal setpoint by the same amount (% RTP) as the power reduction required by Figure 3.2-1.

c. With the combination of Reactor Coolant System total flow rate and THERMAL POWER within the region of prohibited operation specified on Figure 3.2-1:

1. Within 2 hours either:

a) Restore the combination of Reactor Coolant System total flow rate and THERMAL POWER to within the region of permissible operation, or

b) Restore the combination of Reactor Coolant System total flow rate and THERMAL POWER to within the region of restricted operation and comply with action b. above, or

c) Reduce THERMAL POWER to less than 50% of RATED THERMAL POWER and reduce the Power Range Neutron Flux - High Trip Setpoint to less than or equal to 55% of RATED THERMAL POWER within the next 4 hours.

TABLE 3.3-1 FOR UNIT 1

REACTOR TRIP SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
1. Manual Reactor Trip	2	1	2	1, 2	1
	2	1	2	3*, 4*, 5*	10
2. Power Range, Neutron Flux					
a. High Setpoint	4	2	3	1, 2	2
b. Low Setpoint	4	2	3	1###, 2	2
3. Power Range, Neutron Flux High Positive Rate	4	2	3	1, 2	2
4. Intermediate Range, Neutron Flux	2	1	2	1###, 2	3
5. Source Range, Neutron Flux					
a. Startup	2	1	2	2##	4
b. Shutdown	2	1	2	3*, 4*, 5*	10
6. Overtemperature ΔT Four Loop Operation	4	2	3	1, 2	6
7. Overpower ΔT Four Loop Operation	4	2	3	1, 2	6
8. Pressurizer Pressure-Low	4	2	3	1	6**

TABLE 3.3-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
9. Pressurizer Pressure-High	4	2	3	1, 2	6**
10. Pressurizer Water Level-High	3	2	2	1	6
11. Reactor Coolant Flow-Low					
a. Single Loop (Above P-8)	3/loop	2/loop in any operating loop	2/loop in each operating loop	1	6
b. Two Loops (Above P-7 and below P-8)	3/loop	2/loop in two operating loops	2/loop each operating loop	1	6
12. Steam Generator Water Level--Low-Low	4/stm gen	2/stm gen in any operating stm gen	3/stm gen each operating stm gen	1, 2	6**
13. Undervoltage-Reactor Coolant Pumps (Above P-7)	4-1/bus	2	3	1	6
14. Underfrequency-Reactor Coolant Pumps (Above P-7)	4-1/bus	2	3	1	6
15. Turbine Trip					
a. Stop Valve EH Pressure - Low	4	2	3	1####	6
b. Turbine Stop Valve Closure	4	4	1	1####	11
16. Safety Injection Input from ESF	2	1	2	1, 2	9

TABLE 3.3-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
17. Reactor Trip System Interlocks					
a. Intermediate Range Neutron Flux, P-6	2	1	2	2##	8
b. Low Power Reactor Trips Block, P-7					
P-10 Input	4	2	3	1	8
or					
P-13 Input	2	1	2	1	8
c. Power Range Neutron Flux, P-8	4	2	3	1	8
d. Power Range Neutron Flux, P-9	4	2	3	1	8
e. Power Range Neutron Flux, P-10	4	2	3	1	8
f. Power Range Neutron Flux, Not P-10	4	3	4	1, 2	8
g. Turbine Impulse Chamber Pressure, P-13	2	1	2	1	8
18. Reactor Trip Breakers	2	1	2	1, 2	9, 12
	2	1	2	3*, 4*, 5*	10
19. Automatic Trip and Interlock Logic	2	1	2	1, 2	9
	2	1	2	3*, 4*, 5*	10
20. Reactor Trip Bypass Breakers	N.A.	N.A.	N.A.	1,2,3*,4*,5*	13

TABLE NOTATIONS

*Only if the Reactor Trip System breakers happen to be in the closed position and the Control Rod Drive System is capable of rod withdrawal.
**Comply with the provisions of Specification 3.3.2, for any portion of the channel required to be OPERABLE by Specification 3.3.2.

##Below the P-6 (Intermediate Range Neutron Flux Interlock) Setpoint.
###Below the P-10 (Low Setpoint Power Range Neutron Flux Interlock) Setpoint.
####Above the P-9 (Reactor Trip on Turbine Trip Interlock) Setpoint.

ACTION STATEMENTS

ACTION 1 - 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 be in at least HOT STANDBY within the next 6 hours.

ACTION 2 - With the number of OPERABLE channels one less than the Total Number of Channels, STARTUP and/or POWER OPERATION may proceed provided the following conditions are satisfied:

a. The inoperable channel is placed in the tripped condition within 6 hours,

b. The Minimum Channels OPERABLE requirement is met; however, the inoperable channel may be bypassed for up to 4 hours for surveillance testing of other channels per Specification 4.3.1.1, and

c. Either, THERMAL POWER is restricted to less than or equal to 75% of RATED THERMAL POWER and the Power Range Neutron Flux trip setpoint is reduced to less than or equal to 85% of RATED THERMAL POWER within 4 hours; or, the QUADRANT POWER TILT RATIO is monitored at least once per 12 hours per Specification 4.2.4.2.

ACTION 3 - With the number of channels OPERABLE one less than the Minimum Channels OPERABLE requirement and with the THERMAL POWER level:

a. Below the P-6 (Intermediate Range Neutron Flux Interlock) Setpoint, restore the inoperable channel to OPERABLE status prior to increasing THERMAL POWER above the P-6 Setpoint; or

b. Above the P-6 (Intermediate Range Neutron Flux Interlock) Setpoint but below 10% of RATED THERMAL POWER, restore the inoperable channel to OPERABLE status prior to increasing THERMAL POWER above 10% of RATED THERMAL POWER.

TABLE 3.3-1 (Continued)

ACTION STATEMENTS (Continued)

ACTION 4 - With the number of OPERABLE channels one less than the Minimum Channels OPERABLE requirement, suspend all operations involving positive reactivity changes.

ACTION 5 - Delete

ACTION 6 - With the number of OPERABLE channels one less than the Total Number of Channels, STARTUP and/or POWER OPERATION may proceed provided the following conditions are satisfied:

a. The inoperable channel is placed in the tripped condition within 6 hours, and

b. The Minimum Channels OPERABLE requirement is met; however, the inoperable channel may be bypassed for up to 4 hours for surveillance testing of other channels per Specification 4.3.1.1.

ACTION 7 - Delete

ACTION 8 - With less than the Minimum Number of Channels OPERABLE, within 1 hour determine by observation of the associated permissive status light(s) that the interlock is in its required state for the existing plant condition, or apply Specification 3.0.3.

ACTION 9 - With the number of OPERABLE channels one less than the Minimum Channels OPERABLE requirement, be in at least HOT STANDBY within 6 hours; however, one channel may be bypassed for up to 2 hours for surveillance testing per Specification 4.3.1.1, provided the other channel is OPERABLE.

ACTION 10 - 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.

ACTION 11 - With the number of OPERABLE channels less than the Total Number of Channels, operation may continue provided the inoperable channels are placed in the tripped condition within 6 hours.

ACTION 12 - With one of the diverse trip features (Undervoltage or shunt trip attachment) inoperable, restore it to OPERABLE status within 48 hours or declare the breaker inoperable and apply ACTION 9. The breaker shall not be bypassed while one of the diverse trip features is inoperable except for the time required for performing maintenance to restore the breaker to OPERABLE status. With the breaker bypassed, apply ACTION 9.

ACTION 13 - With any reactor trip bypass breaker inoperable, restore the bypass breaker to OPERABLE status prior to placing it in service.

TABLE 3.3-2 FOR UNIT 1

REACTOR TRIP SYSTEM INSTRUMENTATION RESPONSE TIMES

FUNCTIONAL UNIT	RESPONSE TIME
1. Manual Reactor Trip	N.A.
2. Power Range, Neutron Flux	≤ 0.5 second*
3. Power Range, Neutron Flux, High Positive Rate	N.A.
4. Intermediate Range, Neutron Flux	N.A.
5. Source Range, Neutron Flux	N.A.
6. Overtemperature ΔT	≤ 8 seconds*
7. Overpower ΔT	≤ 8 seconds*
8. Pressurizer Pressure-Low	≤ 2 seconds
9. Pressurizer Pressure-High	≤ 2 seconds
10. Pressurizer Water Level-High	N.A.

*Neutron detectors are exempt from response time testing. Response time of the neutron flux signal portion of the channel shall be measured from detector output or input of first electronic component in channel.

TABLE 3.3-2 FOR UNIT 1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION RESPONSE TIMES

FUNCTIONAL UNIT	RESPONSE TIME
11. Low Reactor Coolant Flow	
a. Single Loop (Above P-8)	≤ 1 second
b. Two Loops (Above P-7 and below P-8)	≤ 1 second
12. Steam Generator Water Level-Low-Low	
a. Unit 1	≤ 3.5 seconds
b. Unit 2	≤ 2.0 seconds
13. Undervoltage-Reactor Coolant Pumps	≤ 1.5 seconds
14. Underfrequency-Reactor Coolant Pumps	≤ 0.6 second
15. Turbine Trip	
a. Stop Valve EH Pressure-Low	N.A.
b. Turbine Stop Valve Closure	N.A.
16. Safety Injection Input from ESF	N.A.
17. Reactor Trip System Interlocks	N.A.
18. Reactor Trip Breakers	N.A.
19. Automatic Trip and Interlock Logic	N.A.

TABLE 4.3-1 FOR UNIT 1

REACTOR TRIP SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	ANALOG CHANNEL OPERATIONAL TEST	TRIP ACTUATING DEVICE OPERATIONAL TEST	ACTUATION LOGIC TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
1. Manual Reactor Trip	N.A.	N.A.	N.A.	R(14)	N.A.	1, 2, 3*, 4*, 5*
2. Power Range, Neutron Flux						
a. High Setpoint	S	D(2, 4), M(3, 4), Q(4, 6), R(4, 5)	M	N.A.	N.A.	1, 2
b. Low Setpoint	S	R(4)	M	N.A.	N.A.	1###, 2
3. Power Range, Neutron Flux, High Positive Rate	N.A.	R(4)	M	N.A.	N.A.	1, 2
4. Intermediate Range, Neutron Flux	S	R(4, 5)	S/U(1),M	N.A.	N.A.	1###, 2
5. Source Range, Neutron Flux	S	R(4, 5)	S/U(1),M(9)	N.A.	N.A.	2##, 3, 4, 5
6. Overtemperature ΔT	S	R	M	N.A.	N.A.	1, 2
7. Overpower ΔT	S	R	M	N.A.	N.A.	1, 2
8. Pressurizer Pressure-Low	S	R	M	N.A.	N.A.	1
9. Pressurizer Pressure-High	S	R	M	N.A.	N.A.	1, 2
10. Pressurizer Water Level-High	S	R	M	N.A.	N.A.	1
11. Reactor Coolant Flow-Low	S	R	M	N.A.	N.A.	1

TABLE 4.3-1 FOR UNIT 1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	ANALOG CHANNEL OPERATIONAL TEST	TRIP ACTUATING DEVICE OPERATIONAL TEST	ACTUATION LOGIC TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
12. Steam Generator Water Level-Low-Low	S	R(13)	M	N.A.	N.A.	1, 2
13. Undervoltage - Reactor Coolant Pumps	N.A.	R	N.A.	M	N.A.	1
14. Underfrequency - Reactor Coolant Pumps	N.A.	R	N.A.	M	N.A.	1
15. Turbine Trip						
a. Stop Valve EH Pressure - Low	N.A.	R	N.A.	S/U(1, 10)	N.A.	1#
b. Turbine Stop Valve Closure	N.A.	R	N.A.	S/U(1, 10)	N.A.	1#
16. Safety Injection Input from ESF	N.A.	N.A.	N.A.	R**	N.A.	1, 2
17. Reactor Trip System Interlocks						
a. Intermediate Range Neutron Flux, P-6	N.A.	R(4)	M	N.A.	N.A.	2##
b. Low Power Reactor Trips Block, P-7	N.A.	R(4)	M(8)	N.A.	N.A.	1
c. Power Range Neutron Flux, P-8	N.A.	R(4)	M(8)	N.A.	N.A.	1
d. Low Power Range Neutron Flux, P-9	N.A.	R(4)	M(8)	N.A.	N.A.	1

** This surveillance need not be performed until prior to entering STARTUP following the Unit 1 first refueling.

TABLE 4.3-1 FOR UNIT 1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	ANALOG CHANNEL OPERATIONAL TEST	TRIP ACTUATING DEVICE OPERATIONAL TEST	ACTUATION LOGIC TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
17. Reactor Trip System Interlocks (Continued)						
e. Power Range Neutron Flux, P-10	N.A.	R(4)	M(8)	N.A.	N.A.	1
f. Power Range Neutron Flux, Not P-10	N.A.	R(4)	M(8)	N.A.	N.A.	1, 2
g. Turbine Impulse Chamber Pressure, P-13	N.A.	R	M(8)	N.A.	N.A.	1
18. Reactor Trip Breaker	N.A.	N.A.	N.A.	M(7, 11)	N.A.	1, 2, 3*, 4*, 5*
19. Automatic Trip and Interlock Logic	N.A.	N.A.	N.A.	N.A.	M(7)	1, 2, 3*, 4*, 5*
20. Reactor Trip Bypass Breakers	N.A.	N.A.	N.A.	M(7,15)R(16)	N.A	1, 2, 3*, 4*, 5*

TABLE 4.3-1 FOR UNIT 1 (Continued)

TABLE NOTATIONS

* Only if the Reactor Trip System breakers happen to be closed and the Control Rod Drive System is capable of rod withdrawal.

\# Above P-9 (Reactor Trip on Turbine Trip Interlock) Setpoint.

\## Below P-6 (Intermediate Range Neutron Flux Interlock) Setpoint.

\### Below P-10 (Low Setpoint Power Range Neutron Flux Interlock) Setpoint.

(1) If not performed in previous 7 days.

(2) Comparison of calorimetric to excore power indication above 15% of RATED THERMAL POWER. Adjust excore channel gains consistent with calorimetric power if absolute difference is greater than 2%. The provisions of Specification 4.0.4 are not applicable for entry into MODE 2 or 1.

(3) Single point comparison of incore to excore axial flux difference above 15% of RATED THERMAL POWER. Recalibrate if the absolute difference is greater than or equal to 3%. The provisions of Specification 4.0.4 are not applicable for entry into MODE 2 or 1.

(4) Neutron detectors may be excluded from CHANNEL CALIBRATION.

(5) Detector plateau curves shall be obtained, evaluated and compared to manufacturer's data. For the Intermediate Range and Power Range Neutron Flux channels the provisions of Specification 4.0.4 are not applicable for entry into MODE 2 or 1.

(6) Incore - Excore Calibration, above 75% of RATED THERMAL POWER. The provisions of Specification 4.0.4 are not applicable for entry into MODE 2 or 1.

(7) Each train shall be tested at least every 62 days on a STAGGERED TEST BASIS.

(8) With power greater than or equal to the interlock setpoint the required ANALOG CHANNEL OPERATIONAL TEST shall consist of verifying that the interlock is in the required state by observing the permissive status light.

(9) Monthly surveillance in MODES 3*, 4*, and 5* shall also include verification that permissives P-6 and P-10 are in their required state for existing plant conditions by observation of the permissive status light.

(10) Setpoint verification is not applicable.

(11) The TRIP ACTUATING DEVICE OPERATIONAL TEST shall include independent verification of the operability of the Undervoltage and Shunt trips.

(12) Deleted

(13) For Unit 1, CHANNEL CALIBRATION shall ensure that the filter time constant associated with Steam Generator Water Level Low-Low is adjusted to a value less than or equal to 1.5 seconds.

(14) The TRIP ACTUATING DEVICE OPERATIONAL TEST shall independently verify the OPERABILITY of the undervoltage and shunt trip circuits for the Manual Reactor Trip Function. The test shall also verify the OPERABILITY of the Bypass Breaker trip circuit(s).

TABLE 4.3-1 FOR UNIT 1 (Continued)

TABLE NOTATIONS

(15) A local manual shunt trip on the bypass breakers shall be performed prior to placing breaker in service.

(16) The automatic undervoltage trip capability shall be verified OPERABLE.

TABLE 3.3-1 FOR UNIT 2

REACTOR TRIP SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
1. Manual Reactor Trip	2	1	2	1, 2	1
	2	1	2	3*, 4*, 5*	10
2. Power Range, Neutron Flux					
a. High Setpoint	4	2	3	1, 2	2
b. Low Setpoint	4	2	3	1###, 2	2
3. Power Range, Neutron Flux High Positive Rate	4	2	3	1, 2	2
4. Power Range, Neutron Flux, High Negative Rate	4	2	3	1, 2	2
5. Intermediate Range, Neutron Flux	2	1	2	1###, 2	3
6. Source Range, Neutron Flux					
a. Startup	2	1	2	2##	4
b. Shutdown	2	1	2	3*, 4*, 5*	10
7. Overtemperature ΔT Four Loop Operation	4	2	3	1, 2	6
8. Overpower ΔT Four Loop Operation	4	2	3	1, 2	6
9. Pressurizer Pressure-Low	4	2	3	1	6**

Amendment No. 101 (Unit 1)
Amendment No. 95 (Unit 2)

TABLE 3.3-1 FOR UNIT 2 (Continued)

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
10. Pressurizer Pressure-High	4	2	3	1, 2	6**
11. Pressurizer Water Level-High	3	2	2	1	6
12. Reactor Coolant Flow-Low					
a. Single Loop (Above P-8)	3/loop any operating loop	2/loop in each operating loop	2/loop in	1	6
b. Two Loops (Above P-7 and below P-8)	3/loop two operating loops	2/loop in each operating loop	2/loop	1	6
13. Steam Generator Water Level--Low-Low	4/stm gen	2/stm gen in any operating stm gen	3/stm gen each operating stm gen	1, 2	6**
14. Undervoltage-Reactor Coolant Pumps (Above P-7)	4-1/bus	2	3	1	6
15. Underfrequency-Reactor Coolant Pumps (Above P-7)	4-1/bus	2	3	1	6
16. Turbine Trip					
a. Stop Valve EH Pressure - Low	4	2	3	1####	6
b. Turbine Stop Valve Closure	4	4	1	1####	11
17. Safety Injection Input from ESF	2	1	2	1, 2	9

TABLE 3.3-1 FOR UNIT 2 (Continued)

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
18. Reactor Trip System Interlocks					
a. Intermediate Range Neutron Flux, P-6	2	1	2	2##	8
b. Low Power Reactor Trips Block, P-7					
P-10 Input	4	2	3	1	8
or P-13 Input	2	1	2	1	8
c. Power Range Neutron Flux, P-8	4	2	3	1	8
d. Power Range Neutron Flux, P-9	4	2	3	1	8
e. Power Range Neutron Flux, P-10	4	2	3	1	8
f. Power Range Neutron Flux, Not P-10	4	3	4	1, 2	8
g. Turbine Impulse Chamber Pressure, P-13	2	1	2	1	8
19. Reactor Trip Breakers	2	1	2	1, 2	9, 12
	2	1	2	3*, 4*, 5*	10
20. Automatic Trip and Interlock Logic	2	1	2	1, 2	9
	2	1	2	3*, 4*, 5*	10
21. Reactor Trip Bypass Breakers	N.A.	N.A.	N.A.	1, 2, 3*, 4*, 5*	13

TABLE 3.3-1 FOR UNIT 2 (Continued)

TABLE NOTATIONS

*Only if the Reactor Trip System breakers happen to be in the closed position and the Control Rod Drive System is capable of rod withdrawal.
**Comply with the provisions of Specification 3.3.2, for any portion of the channel required to be OPERABLE by Specification 3.3.2.

##Below the P-6 (Intermediate Range Neutron Flux Interlock) Setpoint.
###Below the P-10 (Low Setpoint Power Range Neutron Flux Interlock) Setpoint.
####Above the P-9 (Reactor Trip on Turbine Trip Interlock) Setpoint.

ACTION STATEMENTS

ACTION 1 - 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 be in at least HOT STANDBY within the next 6 hours.

ACTION 2 - With the number of OPERABLE channels one less than the Total Number of Channels, STARTUP and/or POWER OPERATION may proceed provided the following conditions are satisfied:

a. The inoperable channel is placed in the tripped condition within 6 hours,

b. The Minimum Channels OPERABLE requirement is met; however, the inoperable channel may be bypassed for up to 4 hours for surveillance testing of other channels per Specification 4.3.1.1, and

c. Either, THERMAL POWER is restricted to less than or equal to 75% of RATED THERMAL POWER and the Power Range Neutron Flux trip setpoint is reduced to less than or equal to 85% of RATED THERMAL POWER within 4 hours; or, the QUADRANT POWER TILT RATIO is monitored at least once per 12 hours per Specification 4.2.4.2.

ACTION 3 - With the number of channels OPERABLE one less than the Minimum Channels OPERABLE requirement and with the THERMAL POWER level:

a. Below the P-6 (Intermediate Range Neutron Flux Interlock) Setpoint, restore the inoperable channel to OPERABLE status prior to increasing THERMAL POWER above the P-6 Setpoint; or

b. Above the P-6 (Intermediate Range Neutron Flux Interlock) Setpoint but below 10% of RATED THERMAL POWER, restore the inoperable channel to OPERABLE status prior to increasing THERMAL POWER above 10% of RATED THERMAL POWER.

TABLE 3.3-1 FOR UNIT 2 (Continued)

ACTION STATEMENTS (Continued)

ACTION 4 - With the number of OPERABLE channels one less than the Minimum Channels OPERABLE requirement, suspend all operations involving positive reactivity changes.

ACTION 5 - Delete

ACTION 6 - With the number of OPERABLE channels one less than the Total Number of Channels, STARTUP and/or POWER OPERATION may proceed provided the following conditions are satisfied:

a. The inoperable channel is placed in the tripped condition within 6 hours, and

b. The Minimum Channels OPERABLE requirement is met; however, the inoperable channel may be bypassed for up to 4 hours for surveillance testing of other channels per Specification 4.3.1.1.

ACTION 7 - Delete

ACTION 8 - With less than the Minimum Number of Channels OPERABLE, within 1 hour determine by observation of the associated permissive status light(s) that the interlock is in its required state for the existing plant condition, or apply Specification 3.0.3.

ACTION 9 - With the number of OPERABLE channels one less than the Minimum Channels OPERABLE requirement, be in at least HOT STANDBY within 6 hours; however, one channel may be bypassed for up to 2 hours for surveillance testing per Specification 4.3.1.1, provided the other channel is OPERABLE.

ACTION 10 - 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.

ACTION 11 - With the number of OPERABLE channels less than the Total Number of Channels, operation may continue provided the inoperable channels are placed in the tripped condition within 6 hours.

ACTION 12 - With one of the diverse trip features (Undervoltage or shunt trip attachment) inoperable, restore it to OPERABLE status within 48 hours or declare the breaker inoperable and apply ACTION 9. The breaker shall not be bypassed while one of the diverse trip features is inoperable except for the time required for performing maintenance to restore the breaker to OPERABLE status. With the breaker bypassed, apply ACTION 9.

ACTION 13 - With any reactor trip bypass breaker inoperable, restore the bypass breaker to OPERABLE status prior to placing it in service.

TABLE 3.3-2 FOR UNIT 2

REACTOR TRIP SYSTEM INSTRUMENTATION RESPONSE TIMES

FUNCTIONAL UNIT	RESPONSE TIME
1. Manual Reactor Trip	N.A.
2. Power Range, Neutron Flux	≤ 0.5 second*
3. Power Range, Neutron Flux, High Positive Rate	N.A.
4. Power Range, Neutron Flux, High Negative Rate	≤ 0.5 second*
5. Intermediate Range, Neutron Flux	N.A.
6. Source Range, Neutron Flux	N.A.
7. Overtemperature ΔT	≤ 8 seconds*
8. Overpower ΔT	≤ 8 seconds*
9. Pressurizer Pressure-Low	≤ 2 seconds
10. Pressurizer Pressure-High	≤ 2 seconds
11. Pressurizer Water Level-High	N.A.

*Neutron detectors are exempt from response time testing. Response time of the neutron flux signal portion of the channel shall be measured from detector output or input of first electronic component in channel.

TABLE 3.3-2 FOR UNIT 2 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION RESPONSE TIMES

FUNCTIONAL UNIT	RESPONSE TIME
12. Low Reactor Coolant Flow	
a. Single Loop (Above P-8)	≤ 1 second
b. Two Loops (Above P-7 and below P-8)	≤ 1 second
13. Steam Generator Water Level-Low-Low	
a. Unit 1	≤ 3.5 seconds
b. Unit 2	≤ 2.0 seconds
14. Undervoltage-Reactor Coolant Pumps	≤ 1.5 seconds
15. Underfrequency-Reactor Coolant Pumps	≤ 0.6 second
16. Turbine Trip	
a. Stop Valve EH Pressure-Low	N.A.
b. Turbine Stop Valve Closure	N.A.
17. Safety Injection Input from ESF	N.A.
18. Reactor Trip System Interlocks	N.A.
19. Reactor Trip Breakers	N.A.
20. Automatic Trip and Interlock Logic	N.A.

TABLE 4.3-1 FOR UNIT 2

REACTOR TRIP SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	ANALOG CHANNEL OPERATIONAL TEST	TRIP ACTUATING DEVICE OPERATIONAL TEST	ACTUATION LOGIC TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
1. Manual Reactor Trip	N.A.	N.A.	N.A.	R(14)	N.A.	1, 2, 3*,
2. Power Range, Neutron Flux						
a. High Setpoint	S	D(2, 4), M(3, 4), Q(4, 6), R(4, 5)	M	N.A.	N.A.	1, 2
b. Low Setpoint	S	R(4)	M	N.A.	N.A.	1###, 2
3. Power Range, Neutron Flux, High Positive Rate	N.A.	R(4)	M	N.A.	N.A.	1, 2
4. Power Range, Neutron Flux, High Negative Rate	N.A.	R(4)	M	N.A.	N.A.	1, 2
5. Intermediate Range, Neutron Flux	S	R(4, 5)	S/U(1),M	N.A.	N.A.	1###, 2
6. Source Range, Neutron Flux	S	R(4, 5)	S/U(1),M(9)	N.A.	N.A.	2##, 3, 4, 5
7. Overtemperature ΔT	S	R	M	N.A.	N.A.	1, 2
8. Overpower ΔT	S	R	M	N.A.	N.A.	1, 2
9. Pressurizer Pressure-Low	S	R	M	N.A.	N.A.	1
10. Pressurizer Pressure-High	S	R	M	N.A.	N.A.	1, 2
11. Pressurizer Water Level-High	S	R	M	N.A.	N.A.	1
12. Reactor Coolant Flow-Low	S	R	M	N.A.	N.A.	1

TABLE 4.3-1 FOR UNIT 2 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	ANALOG CHANNEL OPERATIONAL TEST	TRIP ACTUATING DEVICE OPERATIONAL TEST	ACTUATION LOGIC TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
13. Steam Generator Water Level-Low-Low	S	R(13)	M	N.A.	N.A.	1, 2
14. Undervoltage - Reactor Coolant Pumps	N.A.	R	N.A.	M	N.A.	1
15. Underfrequency - Reactor Coolant Pumps	N.A.	R	N.A.	M	N.A.	1
16. Turbine Trip						
a. Stop Valve EH Pressure - Low	N.A.	R	N.A.	S/U(1, 10)	N.A.	1#
b. Turbine Stop Valve Closure	N.A.	R	N.A.	S/U(1, 10)	N.A.	1#
17. Safety Injection Input from ESF	N.A.	N.A.	N.A.	R**	N.A.	1, 2
18. Reactor Trip System Interlocks						
a. Intermediate Range Neutron Flux, P-6	N.A.	R(4)	M	N.A.	N.A.	2##
b. Low Power Reactor Trips Block, P-7	N.A.	R(4)	M(8)	N.A.	N.A.	1
c. Power Range Neutron Flux, P-8	N.A.	R(4)	M(8)	N.A.	N.A.	1
d. Low Power Range Neutron Flux, P-9	N.A.	R(4)	M(8)	N.A.	N.A.	1

** This surveillance need not be performed until prior to entering STARTUP following the Unit 1 first refueling.

TABLE 4.3-1 FOR UNIT 2 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	ANALOG CHANNEL OPERATIONAL TEST	TRIP ACTUATING DEVICE OPERATIONAL TEST	ACTUATION LOGIC TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
18. Reactor Trip System Interlocks (Continued)						
e. Power Range Neutron Flux, P-10	N.A.	R(4)	M(8)	N.A.	N.A.	1
f. Power Range Neutron Flux, Not P-10	N.A.	R(4)	M(8)	N.A.	N.A.	1, 2
g. Turbine Impulse Chamber Pressure, P-13	N.A.	R	M(8)	N.A.	N.A.	1
19. Reactor Trip Breaker	N.A.	N.A.	N.A.	M(7, 11)	N.A.	1, 2, 3*, 4*, 5*
20. Automatic Trip and Interlock Logic	N.A.	N.A.	N.A.	N.A.	M(7)	1, 2, 3*, 4*, 5*
21. Reactor Trip Bypass Breakers	N.A.	N.A.	N.A	M(7,15)R(16)	N.A	1, 2, 3*, 4* 5*

TABLE 4.3-1 FOR UNIT 2 (Continued)

TABLE NOTATIONS

* Only if the Reactor Trip System breakers happen to be closed and the Control Rod Drive System is capable of rod withdrawal.

\# Above P-9 (Reactor Trip on Turbine Trip Interlock) Setpoint.

\## Below P-6 (Intermediate Range Neutron Flux Interlock) Setpoint.

\### Below P-10 (Low Setpoint Power Range Neutron Flux Interlock) Setpoint.

(1) If not performed in previous 7 days.

(2) Comparison of calorimetric to excore power indication above 15% of RATED THERMAL POWER. Adjust excore channel gains consistent with calorimetric power if absolute difference is greater than 2%. The provisions of Specification 4.0.4 are not applicable for entry into MODE 2 or 1.

(3) Single point comparison of incore to excore axial flux difference above 15% of RATED THERMAL POWER. Recalibrate if the absolute difference is greater than or equal to 3%. The provisions of Specification 4.0.4 are not applicable for entry into MODE 2 or 1.

(4) Neutron detectors may be excluded from CHANNEL CALIBRATION.

(5) Detector plateau curves shall be obtained, evaluated and compared to manufacturer's data. For the Intermediate Range and Power Range Neutron Flux channels the provisions of Specification 4.0.4 are not applicable for entry into MODE 2 or 1.

(6) Incore - Excore Calibration, above 75% of RATED THERMAL POWER. The provisions of Specification 4.0.4 are not applicable for entry into MODE 2 or 1.

(7) Each train shall be tested at least every 62 days on a STAGGERED TEST BASIS.

(8) With power greater than or equal to the interlock setpoint the required ANALOG CHANNEL OPERATIONAL TEST shall consist of verifying that the interlock is in the required state by observing the permissive status light.

(9) Monthly surveillance in MODES 3*, 4*, and 5* shall also include verification that permissives P-6 and P-10 are in their required state for existing plant conditions by observation of the permissive status light.

(10) Setpoint verification is not applicable.

(11) The TRIP ACTUATING DEVICE OPERATIONAL TEST shall include independent verification of the Undervoltage and Shunt trips.

(12) Deleted

(13) For Unit 1, CHANNEL CALIBRATION shall ensure that the filter time constant associated with Steam Generator Water Level Low-Low is adjusted to a value less than or equal to 1.5 seconds.

(14) The TRIP ACTUATING DEVICE OPERATIONAL TEST shall independently verify the OPERABILITY of the undervoltage and shunt trip circuits for the Manual Reactor Trip Function. The test shall also verify the OPERABILITY of the Bypass Breaker trip circuit(s).

TABLE 4.3-1 FOR UNIT 2 (Continued)

TABLE NOTATIONS

(15) A local manual shunt trip on the bypass breakers shall be performed prior to placing breaker in service.

(16) The automatic undervoltage trip capability shall be verified OPERABLE.

3/4.3.2 ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.2 The Engineered Safety Features Actuation System (ESFAS) instrumentation channels and interlocks shown in Table 3.3-3 shall be OPERABLE with their Trip Setpoints set consistent with the values shown in the Trip Setpoint column of Table 3.3-4 and with RESPONSE TIMES as shown in Table 3.3-5.

APPLICABILITY: As shown in Table 3.3-3

ACTION:

a. With an ESFAS Instrumentation or Interlock Trip Setpoint trip less conservative than the value shown in the Trip Setpoint column but more conservative than the value shown in the Allowable Value column of Table 3.3-4, adjust the Setpoint consistent with the Trip Setpoint value.

b. With an ESFAS Instrumentation or Interlock Trip Setpoint less conservative than the value shown in the Allowable Values Column of Table 3.3-4 declare the channel inoperable and apply the applicable ACTION statement requirements of Table 3.3.3 until the channel is restored to OPERABLE status with its Setpoint adjusted consistent with the Trip Setpoint value.

c. With an ESFAS instrumentation channel or interlock inoperable, take the ACTION shown in Table 3.3-3.

TABLE 3.3-4 For Unit 1

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUE
1. Safety Injection (Reactor Trip, Phase "A" Isolation, Feedwater Isolation, Control Room Area Ventilation Operation, Auxiliary Feedwater-Motor-Driven Pump, Purge & Exhaust Isolation, Annulus Ventilation Operation, Auxiliary Building Filtered Exhaust Operation, Emergency Diesel Generator Operation, Component Cooling Water, Turbine Trip, and Nuclear Service Water Operation)		
a. Manual Initiation	N.A.	N.A.
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
c. Containment Pressure-High	$\leq$ 1.2 psig	$\leq$ 1.4 psig
d. Pressurizer Pressure-Low	$\geq$ 1845 psig	$\geq$ 1839 psig
e. Steam Line Pressure-Low	$\geq$ 775 psig	$\geq$ 744 psig
2. Containment Spray		
a. Manual Initiation	N.A.	N.A.
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
c. Containment Pressure-High-High	$\leq$ 3 psig	$\leq$ 3.2 psig

TABLE 3.3-4 For Unit 1 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUE
3. Containment Isolation		
a. Phase "A" Isolation		
1) Manual Initiation	N.A.	N.A.
2) Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
3) Safety Injection	See Item 1. above for all Safety Injection Setpoints and Allowable Values.	
b. Phase "B" Isolation (Nuclear Service Water Operation)		
1) Manual Initiation	N.A.	N.A.
2) Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
3) Containment Pressure-High-High	$\leq$ 3 psig	$\leq$ 3.2 psig
c. Purge and Exhaust Isolation		
1) Manual Initiation	N.A.	N.A.
2) Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
3) Safety Injection	See Item 1. above for all Safety Injection Setpoints and Allowable Values.	

TABLE 3.3-4 For Unit 1 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUE
4. Steam Line Isolation		
a. Manual Initiation	N.A.	N.A.
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
c. Containment Pressure-High-High	≤ 3 psig	≤ 3.2 psig
d. Steam Line Pressure - Low	≥ 775 psig	≥ 744 psig
e. Steam Line Pressure-Negative Rate - High	≤ 100 psi	≤ 122.8 psi**
5. Feedwater Isolation		
a. Automatic Actuation Logic Actuation Relays	N.A.	N.A.
b. Steam Generator Water Level-High-High (P-14)		
1. Unit 1	≤ 82.4% of narrow range instrument span	≤ 84.2% of narrow range instrument span
2. Unit 2	≤ 77.1% of narrow range instrument span	≤ 78.9% of narrow range instrument span
c. T_{avg}-Low	≥ 564°F	≥ 561°F
d. Doghouse Water Level-High	11 inches above 577' floor level	12 inches above 577' floor level
e. Safety Injection	See Item 1. above for all Safety Injection Setpoints and Allowable Values.	

TABLE 3.3-4 For Unit 1 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUE
6. Turbine Trip		
a. Manual Initiation	N.A.	N.A.
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
c. Steam Generator Water Level-High-High (P-14)		
1. Unit 1	≤ 82.4% of narrow range instrument span	≤ 84.2% of narrow range instrument span
2. Unit 2	≤ 77.1% of narrow range instrument span	≤ 78.9% of narrow range instrument span
d. Trip of All Main Feedwater Pumps	N.A.	N.A.
e. Reactor Trip (P-4)	N.A.	N.A.
f. Safety Injection	See Item 1. above for all Safety Injection Setpoints and Allowable Values.	
7. Containment Pressure Control System		
a. Start Permissive	≤ 0.4 psid	≤ 0.45 psid
b. Termination	≥ 0.3 psid	≥ 0.25 psid
8. Auxiliary Feedwater		
a. Manual Initiation	N.A	N.A.
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.

TABLE 3.3-4 For Unit 1 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUE
8. Auxiliary Feedwater (Continued)		
c. Steam Generator Water Level - Low-Low		
1) Unit 1	≥ 17% of span from 0% to 30% RTP increasing linearly to ≥ 40.0% of span from 30% to 100% RTP	≥ 15.3% of span from 0% to 30% RTP increasing linearly to ≥ 38.3% of span from 30% to 100% RTP
2) Unit 2	≥ 36.8% of narrow range span	≥ 35.1% of narrow range instrument span
d. Safety Injection	See Item 1. above for all Safety Injection Setpoints and Allowable Values.	
e. Loss-of-Offsite Power	≥ 3500 V	≥ 3200 V
f. Trip of All Main Feedwater Pumps	N.A.	N.A.
g. Auxiliary Feedwater Suction Pressure-Low		
1) CAPS 5220, 5221, 5222	≥ 10.5 psig	≥ 9.5 psig
2) CAPS 5230, 5231, 5232	≥ 6.2 psig	≥ 5.2 psig
a. Unit 1	≥ 6.2 psig	≥ 5.2 psig
b. Unit 2	≥ 6.0 psig	≥ 5.0 psig
9. Containment Sump Recirculation		
a. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
b. Refueling Water Storage Tank Level-Low Coincident With Safety Injection	≥ 177.15 inches	≥ 162.4 inches
	See Item 1. above for all Safety Injection Setpoints and Allowable Values.	

TABLE 3.3-4 For Unit 1 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUE
10. Loss of Power		
a. 4 kV Bus Undervoltage-Loss of Voltage	≥ 3500 V	≥ 3200 V
b. 4 kV Bus Undervoltage-Grid Degraded Voltage	≥ 3685 V	≥ 3611 V
11. Control Room Area Ventilation Operation		
a. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
b. Loss-of-Offsite Power	≥ 3500 V	≥ 3200 V
c. Safety Injection	See Item 1. above for all Safety Injection Setpoints and Allowable Values.	
12. Containment Air Return and Hydrogen Skimmer Operation		
a. Manual Initiation	N.A.	N.A.
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
c. Containment Pressure-High-High	≤ 3 psig	≤ 3.2 psig

TABLE 3.3-4 For Unit 1 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUE
13. Annulus Ventilation Operation		
a. Manual Initiation	N.A.	N.A.
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
c. Safety Injection	See Item 1. above for all Safety Injection Setpoints and Allowable Values.	
14. Nuclear Service Water Operation		
a. Manual Initiation	N.A.	N.A.
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
c. Loss-of-Offsite Power	$\geq$ 3500 V	$\geq$ 3200 V
d. Containment Spray	See Item 2. above for all Containment Spray Setpoints and Allowable Values.	
e. Phase "B" Isolation	See Item 3.b. above for all Phase "B" Isolation Setpoints and Allowable Values.	
f. Safety Injection	See Item 1. above for all Safety Injection Setpoints and Allowable Values.	
g. Suction Transfer-Low Pit Level	$\geq$El. 554.4 ft.	$\geq$El. 552.9 ft.
15. Emergency Diesel Generator Operation (Diesel Building Ventilation Operation, Nuclear Service Water Operation)		
a. Manual Initiation	N.A.	N.A.

TABLE 3.3-4 For Unit 2 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUE
15. Emergency Diesel Generator Operation (Diesel Building Ventilation Operation, Nuclear Service Water Operation) (Continued)		
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
c. Loss-of-Offsite Power	≥ 3500 V	≥ 3200 V
d. Safety Injection	See Item. 1 above for all Safety Injection Setpoints and Allowable Values.	
16. Auxiliary Building Filtered Exhaust Operation		
a. Manual Initiation	N.A.	N.A.
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
c. Safety Injection	See Item 1. above for all Safety Injection Setpoints and Allowable Values.	
17. Diesel Building Ventilation Operation		
a. Manual Initiation	N.A.	N.A.
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
c. Emergency Diesel Generator Operation	See Item 15. above for all Emergency Diesel Generator Operation Setpoints and Allowable Values.	

TABLE 3.3-4 For Unit 1 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUE
18. Engineered Safety Features Actuation System Interlocks		
a. Pressurizer Pressure, P-11	1955 psig	$\geq$1944 psig
b. Pressurizer Pressure, not P-11	1955 psig	$\leq$1966 psig
c. Low-Low T_{avg}, P-12	$\geq$553°F	$\geq$550°F
d. Reactor Trip, P-4	N.A.	N.A.
e. Steam Generator Level, P-14	See Item 5. above for all Steam Generator Water Level Trip Setpoints and Allowable Values.	

TABLE 3.3-4 For Unit 1 (Continued)

TABLE NOTATIONS

**The time constant utilized in the rate-lag controller for Steam Line Pressure-Negative Rate-High is greater than or equal to 50 seconds. Channel calibration shall ensure that this time constant is adjusted to this value.

TABLE 3.3-4 For Unit 2

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUE
1. Safety Injection (Reactor Trip, Phase "A" Isolation, Feedwater Isolation, Control Room Area Ventilation Operation, Auxiliary Feedwater-Motor-Driven Pump, Purge & Exhaust Isolation, Annulus Ventilation Operation, Auxiliary Building Filtered Exhaust Operation, Emergency Diesel Generator Operation, Component Cooling Water, Turbine Trip, and Nuclear Service Water Operation)		
a. Manual Initiation	N.A.	N.A.
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
c. Containment Pressure-High	≤ 1.2 psig	≤ 1.4 psig
d. Pressurizer Pressure-Low	≥ 1845 psig	≥ 1839 psig
e. Steam Line Pressure-Low	≥ 725 psig	≥ 694 psig*
2. Containment Spray		
a. Manual Initiation	N.A.	N.A.
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
c. Containment Pressure-High-High	≤ 3 psig	≤ 3.2 psig

TABLE 3.3-4 For Unit 2 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUE
3. Containment Isolation		
a. Phase "A" Isolation		
1) Manual Initiation	N.A.	N.A.
2) Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
3) Safety Injection	See Item 1. above for all Safety Injection Setpoints and Allowable Values.	
b. Phase "B" Isolation (Nuclear Service Water Operation)		
1) Manual Initiation	N.A.	N.A.
2) Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
3) Containment Pressure-High-High	$\leq$ 3 psig	$\leq$ 3.2 psig
c. Purge and Exhaust Isolation		
1) Manual Initiation	N.A.	N.A.
2) Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
3) Safety Injection	See Item 1. above for all Safety Injection Setpoints and Allowable Values.	

TABLE 3.3-4 For Unit 2 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUE
4. Steam Line Isolation		
a. Manual Initiation	N.A.	N.A.
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
c. Containment Pressure-High-High	≤ 3 psig	≤ 3.2 psig
d. Steam Line Pressure - Low	≥ 725 psig	≥ 694 psig*
e. Steam Line Pressure-Negative Rate - High	≤ 100 psi	≤ 122.8 psi**
5. Feedwater Isolation		
a. Automatic Actuation Logic Actuation Relays	N.A.	N.A.
b. Steam Generator Water Level-High-High (P-14)		
1. Unit 1	≤ 82.4% of narrow range instrument span	≤ 84.2% of narrow range instrument span
2. Unit 2	≤ 77.1% of narrow range instrument span	≤ 78.9% of narrow range instrument span
c. T_{avg}-Low	≥ 564°F	≥ 561°F
d. Doghouse Water Level-High	11 inches above 577' floor level	12 inches above 577' floor level
e. Safety Injection	See Item 1. above for all Safety Injection Setpoints and Allowable Values.	

TABLE 3.3-4 For Unit 2 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUE
6. Turbine Trip		
a. Manual Initiation	N.A.	N.A.
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
c. Steam Generator Water Level-High-High (P-14)		
1. Unit 1	≤ 82.4% of narrow range instrument span	≤ 84.2% of narrow range instrument span
2. Unit 2	≤ 77.1% of narrow range instrument span	≤ 78.9% of narrow range instrument span
d. Trip of All Main Feedwater Pumps	N.A.	N.A.
e. Reactor Trip (P-4)	N.A.	N.A.
f. Safety Injection	See Item 1. above for all Safety Injection Setpoints and Allowable Values.	
7. Containment Pressure Control System		
a. Start Permissive	≤ 0.4 psid	≤ 0.45 psid
b. Termination	≥ 0.3 psid	≥ 0.25 psid
8. Auxiliary Feedwater		
a. Manual Initiation	N.A	N.A.
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.

TABLE 3.3-4 For Unit 2 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUE
8. Auxiliary Feedwater (Continued)		
c. Steam Generator Water Level - Low-Low		
1) Unit 1	≥ 17% of span from 0% to 30% RTP increasing linearly to ≥ 40.0% of span from 30% to 100% RTP	≥ 15.3% of span from 0% to 30% RTP increasing linearly to ≥ 38.3% of span from 30% to 100% RTP
2) Unit 2	≥ 36.8% of narrow range span	≥ 35.1% of narrow range instrument span
d. Safety Injection	See Item 1. above for all Safety Injection Setpoints and Allowable Values.	
e. Loss-of-Offsite Power	≥ 3500 V	≥ 3200 V
f. Trip of All Main Feedwater Pumps	N.A.	N.A.
g. Auxiliary Feedwater Suction Pressure-Low		
1) CAPS 5220, 5221, 5222	≥ 10.5 psig	≥ 9.5 psig
2) CAPS 5230, 5231, 5232	≥ 6.2 psig	≥ 5.2 psig
a. Unit 1	≥ 6.2 psig	≥ 5.2 psig
b. Unit 2	≥ 6.0 psig	≥ 5.0 psig
9. Containment Sump Recirculation		
a. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
b. Refueling Water Storage Tank Level-Low Coincident With Safety Injection	≥ 177.15 inches	≥ 162.4 inches
	See Item 1. above for all Safety Injection Setpoints and Allowable Values.	

TABLE 3.3-4 For Unit 2 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUE
10. Loss of Power		
a. 4 kV Bus Undervoltage-Loss of Voltage	≥ 3500 V	≥ 3200 V
b. 4 kV Bus Undervoltage-Grid Degraded Voltage	≥ 3685 V	≥ 3611 V
11. Control Room Area Ventilation Operation		
a. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
b. Loss-of-Offsite Power	≥ 3500 V	≥ 3200 V
c. Safety Injection	See Item 1. above for all Safety Injection Setpoints and Allowable Values.	
12. Containment Air Return and Hydrogen Skimmer Operation		
a. Manual Initiation	N.A.	N.A.
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
c. Containment Pressure-High-High	≤ 3 psig	≤ 3.2 psig

TABLE 3.3-4 For Unit 2 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUE
13. Annulus Ventilation Operation		
a. Manual Initiation	N.A.	N.A.
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
c. Safety Injection	See Item 1. above for all Safety Injection Setpoints and Allowable Values.	
14. Nuclear Service Water Operation		
a. Manual Initiation	N.A.	N.A.
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
c. Loss-of-Offsite Power	≥ 3500 V	≥ 3200 V
d. Containment Spray	See Item 2. above for all Containment Spray Setpoints and Allowable Values.	
e. Phase "B" Isolation	See Item 3.b. above for all Phase "B" Isolation Setpoints and Allowable Values.	
f. Safety Injection	See Item 1. above for all Safety Injection Setpoints and Allowable Values.	
g. Suction Transfer-Low Pit Level	≥El. 554.4 ft.	≥El. 552.9 ft.
15. Emergency Diesel Generator Operation (Diesel Building Ventilation Operation, Nuclear Service Water Operation)		
a. Manual Initiation	N.A.	N.A.

TABLE 3.3-4 For Unit 2 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUE
15. Emergency Diesel Generator Operation (Diesel Building Ventilation Operation, Nuclear Service Water Operation) (Continued)		
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
c. Loss-of-Offsite Power	≥ 3500 V	≥ 3200 V
d. Safety Injection	See Item. 1 above for all Safety Injection Setpoints and Allowable Values.	
16. Auxiliary Building Filtered Exhaust Operation		
a. Manual Initiation	N.A.	N.A.
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
c. Safety Injection	See Item 1. above for all Safety Injection Setpoints and Allowable Values.	
17. Diesel Building Ventilation Operation		
a. Manual Initiation	N.A.	N.A.
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
c. Emergency Diesel Generator Operation	See Item 15. above for all Emergency Diesel Generator Operation Setpoints and Allowable Values.	

TABLE 3.3-4 For Unit 2 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUE
18. Engineered Safety Features Actuation System Interlocks		
a. Pressurizer Pressure, P-11	1955 psig	≥1944 psig
b. Pressurizer Pressure, not P-11	1955 psig	≤1966 psig
c. Low-Low T_{avg}, P-12	≥553°F	≥550°F
d. Reactor Trip, P-4	N.A.	N.A.
e. Steam Generator Level, P-14	See Item 5. above for all Steam Generator Water Level Trip Setpoints and Allowable Values.	

TABLE 3.3-4 For Unit 2 (Continued)

TABLE NOTATIONS

*Time constants utilized in the lead-lag controller for Steam Line Pressure-Low are $\tau_1 \geq 50$ seconds and $\tau_2 \leq 5$ seconds. Channel calibration shall ensure that these time constants are adjusted to these values.

**The time constant utilized in the rate-lag controller for Steam Line Pressure-Negative Rate-High is greater than or equal to 50 seconds. Channel calibration shall ensure that this time constant is adjusted to this value.

TABLE 3.3-5 FOR UNIT 1

ENGINEERED SAFETY FEATURES RESPONSE TIMES

INITIATION SIGNAL AND FUNCTION	RESPONSE TIME IN SECONDS
1. Manual Initiation	
a. Safety Injection (ECCS)	N.A.
b. Containment Spray	N.A.
c. Phase "A" Isolation	N.A.
d. Phase "B" Isolation	N.A.
e. Purge and Exhaust Isolation	N.A.
f. Steam Line Isolation	N.A.
g. Diesel Building Ventilation Operation	N.A.
h. Nuclear Service Water Operation	N.A.
i. Turbine Trip	N.A.
j. Component Cooling Water	N.A.
k. Annulus Ventilation Operation	N.A.
l. Auxiliary Building Filtered Exhaust Operation	N.A.
m. Reactor Trip	N.A.
n. Emergency Diesel Generator Operation	N.A.
o. Containment Air Return and Hydrogen Skimmer Operation	N.A.
p. Auxiliary Feedwater	N.A.
2. Containment Pressure-High	
a. Safety Injection (ECCS)	$\leq 27^{(1)}/12^{(3)}$
1) Reactor Trip	≤ 2
2) Feedwater Isolation	≤ 12
3) Phase "A" Isolation[2]	$\leq 18^{(3)}/28^{(4)}$
4) Purge and Exhaust Isolation	≤ 6
5) Auxiliary Feedwater[5]	N.A.
6) Nuclear Service Water Operation	$\leq 65^{(3)}/76^{(4)}$
7) Turbine Trip	N.A.
8) Component Cooling Water	$\leq 65^{(3)}/76^{(4)}$
9) Emergency Diesel Generator Operation	≤ 11
10) Control Room Area Ventilation Operation	N.A.

TABLE 3.3-5 FOR UNIT 1 (Continued)

ENGINEERED SAFETY FEATURES RESPONSE TIMES

INITIATING SIGNAL AND FUNCTION	RESPONSE TIME IN SECONDS
2. Containment Pressure-High (Continued)	
11) Annulus Ventilation Operation	≤ 23
12) Auxiliary Building Filtered Exhaust Operation	N.A.
13) Containment Sump Recirculation	N.A.
3. Pressurizer Pressure-Low	
a. Safety Injection (ECCS)	≤ 27(1)/12(3)
1) Reactor Trip	≤ 2
2) Feedwater Isolation	≤ 12
3) Phase "A" Isolation(2)	≤ 18(3)/28(4)
4) Purge and Exhaust Isolation	≤ 6
5) Auxiliary Feedwater(5)	N.A.
6) Nuclear Service Water Operation	≤ 65(3)/76(4)
7) Turbine Trip	N.A.
8) Component Cooling Water	≤ 65(3)/76(4)
9) Emergency Diesel Generator Operation	≤ 11
10) Control Room Area Ventilation Operation	N.A.
11) Annulus Ventilation Operation	≤ 23
12) Auxiliary Building Filtered Exhaust Operation	N.A.
13) Containment Sump Recirculation	N.A.
4. Steam Line Pressure-Low	
a. Safety Injection (ECCS)	≤ 12(3)/22(4)
1) Reactor Trip	≤ 2
2) Feedwater Isolation	≤ 12
3) Phase "A" Isolation(2)	≤ 18(3)/28(4)
4) Purge and Exhaust Isolation	≤ 6
5) Auxiliary Feedwater(5)	≤ 60
6) Nuclear Service Water Operation	≤ 65(3)/76(4)
7) Turbine Trip	N.A.
8) Component Cooling Water	≤ 65(3)/76(4)
9) Emergency Diesel Generator Operation	≤ 11

TABLE 3.3-5 FOR UNIT 1 (Continued)

ENGINEERED SAFETY FEATURES RESPONSE TIMES

INITIATING SIGNAL AND FUNCTION	RESPONSE TIME IN SECONDS
4. Steam Line Pressure-Low (Continued)	
10) Control Room Area Ventilation Operation	N.A.
11) Annulus Ventilation Operation	≤ 23
12) Auxiliary Building Filtered Exhaust Isolation	N.A.
13) Containment Sump Recirculation	N.A.
b. Steam Line Isolation	≤ 10
5. Containment Pressure-High-High	
a. Containment Spray	≤ 45
b. Phase "B" Isolation	≤ 65(3)/76(4)
Nuclear Service Water Operation	N.A.
c. Steam Line Isolation	≤ 10
d. Containment Air Return and Hydrogen Skimmer Operation	≤ 600
6. Steam Line Pressure - Negative Rate-High	
Steam Line Isolation	≤ 10
7. Steam Generator Water Level-High-High	
a. Turbine Trip	≤ 3
b. Feedwater Isolation	≤ 12
8. T_{avg}-Low	
Feedwater Isolation	N.A.
9. Doghouse Water Level-High	
Feedwater Isolation	N.A.
10. Start Permissive	
Containment Pressure Control System	N.A.
11. Termination	
Containment Pressure Control System	N.A.

TABLE 3.3-5 FOR UNIT 1 (Continued)

ENGINEERED SAFETY FEATURES RESPONSE TIMES

INITIATING SIGNAL AND FUNCTION	RESPONSE TIME IN SECONDS
12. Steam Generator Water Level-Low-Low	
a. Motor-Driven Auxiliary Feedwater Pumps	≤ 60
b. Turbine-Driven Auxiliary Feedwater Pump	≤ 60
13. Loss-of-Offsite Power	
a. Motor-Driven Auxiliary Feedwater Pumps	≤ 60
b. Turbine-Driven Auxiliary Feedwater Pumps	≤ 60
c. Control Room Area Ventilation Operation	N.A.
d. Emergency Diesel Generator Operation	≤ 11
1) Diesel Building Ventilation Operation	N.A.
2) Nuclear Service Water Operation	≤ 65(3)/76(4)
14. Trip of All Main Feedwater Pumps	
a. Motor-Driven Auxiliary Feedwater Pumps	≤ 60
b. Turbine Trip	N.A.
15. Auxiliary Feedwater Suction Pressure-Low	
Auxiliary Feedwater (Suction Supply Automatic Realignment)	≤ 16(6)
16. Refueling Water Storage Tank Level-Low	
Coincident with Safety Injection Signal (Automatic Switchover to Containment Sump)	≤ 60
17. Loss of Power	
a. 4 kV Bus Undervoltage - Loss of Voltage	≤ 8.5
b. 4 kV Bus Undervoltage- Grid Degraded Voltage	≤ 600
18. Suction Transfer-Low Pit Level	
Nuclear Service Water Operation	N.A.

TABLE 3.3-5 FOR UNIT 2

ENGINEERED SAFETY FEATURES RESPONSE TIMES

INITIATION SIGNAL AND FUNCTION	RESPONSE TIME IN SECONDS
1. Manual Initiation	
a. Safety Injection (ECCS)	N.A.
b. Containment Spray	N.A.
c. Phase "A" Isolation	N.A.
d. Phase "B" Isolation	N.A.
e. Purge and Exhaust Isolation	N.A.
f. Steam Line Isolation	N.A.
g. Diesel Building Ventilation Operation	N.A.
h. Nuclear Service Water Operation	N.A.
i. Turbine Trip	N.A.
j. Component Cooling Water	N.A.
k. Annulus Ventilation Operation	N.A.
l. Auxiliary Building Filtered Exhaust Operation	N.A.
m. Reactor Trip	N.A.
n. Emergency Diesel Generator Operation	N.A.
o. Containment Air Return and Hydrogen Skimmer Operation	N.A.
p. Auxiliary Feedwater	N.A.
2. Containment Pressure-High	
a. Safety Injection (ECCS)	$\leq 27^{(1)}/12^{(3)}$
1) Reactor Trip	≤ 2
2) Feedwater Isolation	≤ 7
3) Phase "A" Isolation[2]	$\leq 18^{(3)}/28^{(4)}$
4) Purge and Exhaust Isolation	≤ 6
5) Auxiliary Feedwater[5]	N.A.
6) Nuclear Service Water Operation	$\leq 65^{(3)}/76^{(4)}$
7) Turbine Trip	N.A.
8) Component Cooling Water	$\leq 65^{(3)}/76^{(4)}$
9) Emergency Diesel Generator Operation	≤ 11
10) Control Room Area Ventilation Operation	N.A.

TABLE 3.3-5 FOR UNIT 2 (Continued)

ENGINEERED SAFETY FEATURES RESPONSE TIMES

INITIATING SIGNAL AND FUNCTION	RESPONSE TIME IN SECONDS
2. Containment Pressure-High (Continued)	
11) Annulus Ventilation Operation	≤ 23
12) Auxiliary Building Filtered Exhaust Operation	N.A.
13) Containment Sump Recirculation	N.A.
3. Pressurizer Pressure-Low	
a. Safety Injection (ECCS)	≤ 27(1)/12(3)
1) Reactor Trip	≤ 2
2) Feedwater Isolation	≤ 7
3) Phase "A" Isolation(2)	≤ 18(3)/28(4)
4) Purge and Exhaust Isolation	≤ 6
5) Auxiliary Feedwater(5)	N.A.
6) Nuclear Service Water Operation	≤ 65(3)/76(4)
7) Turbine Trip	N.A.
8) Component Cooling Water	≤ 65(3)/76(4)
9) Emergency Diesel Generator Operation	≤ 11
10) Control Room Area Ventilation Operation	N.A.
11) Annulus Ventilation Operation	≤ 23
12) Auxiliary Building Filtered Exhaust Operation	N.A.
13) Containment Sump Recirculation	N.A.
4. Steam Line Pressure-Low	
a. Safety Injection (ECCS)	≤ 12(3)/22(4)
1) Reactor Trip	≤ 2
2) Feedwater Isolation	≤ 7
3) Phase "A" Isolation(2)	≤ 18(3)/28(4)
4) Purge and Exhaust Isolation	≤ 6
5) Auxiliary Feedwater(5)	≤ 60
6) Nuclear Service Water Operation	≤ 65(3)/76(4)
7) Turbine Trip	N.A.
8) Component Cooling Water	≤ 65(3)/76(4)
9) Emergency Diesel Generator Operation	≤ 11

TABLE 3.3-5 FOR UNIT 2 (Continued)

ENGINEERED SAFETY FEATURES RESPONSE TIMES

INITIATING SIGNAL AND FUNCTION	RESPONSE TIME IN SECONDS
4. Steam Line Pressure-Low (Continued)	
10) Control Room Area Ventilation Operation	N.A.
11) Annulus Ventilation Operation	≤ 23
12) Auxiliary Building Filtered Exhaust Isolation	N.A.
13) Containment Sump Recirculation	N.A.
b. Steam Line Isolation	≤ 7
5. Containment Pressure-High-High	
a. Containment Spray	≤ 45
b. Phase "B" Isolation	≤ 65(3)/76(4)
Nuclear Service Water Operation	N.A.
c. Steam Line Isolation	≤ 7
d. Containment Air Return and Hydrogen Skimmer Operation	≤ 600
6. Steam Line Pressure - Negative Rate-High	
Steam Line Isolation	≤ 7
7. Steam Generator Water Level-High-High	
a. Turbine Trip	≤ 3
b. Feedwater Isolation	≤ 7
8. T_{avg}-Low	
Feedwater Isolation	N.A.
9. Doghouse Water Level-High	
Feedwater Isolation	N.A.
10. Start Permissive	
Containment Pressure Control System	N.A.
11. Termination	
Containment Pressure Control System	N.A.

TABLE 3.3-5 FOR UNIT 2 (Continued)

ENGINEERED SAFETY FEATURES RESPONSE TIMES

INITIATING SIGNAL AND FUNCTION	RESPONSE TIME IN SECONDS
12. Steam Generator Water Level-Low-Low	
a. Motor-Driven Auxiliary Feedwater Pumps	≤ 60
b. Turbine-Driven Auxiliary Feedwater Pump	≤ 60
13. Loss-of-Offsite Power	
a. Motor-Driven Auxiliary Feedwater Pumps	≤ 60
b. Turbine-Driven Auxiliary Feedwater Pumps	≤ 60
c. Control Room Area Ventilation Operation	N.A.
d. Emergency Diesel Generator Operation	≤ 11
1) Diesel Building Ventilation Operation	N.A.
2) Nuclear Service Water Operation	≤ 65(3)/76(4)
14. Trip of All Main Feedwater Pumps	
a. Motor-Driven Auxiliary Feedwater Pumps	≤ 60
b. Turbine Trip	N.A.
15. Auxiliary Feedwater Suction Pressure-Low	
Auxiliary Feedwater (Suction Supply Automatic Realignment)	≤ 16(6)
16. Refueling Water Storage Tank Level-Low	
Coincident with Safety Injection Signal (Automatic Switchover to Containment Sump)	≤ 60
17. Loss of Power	
a. 4 kV Bus Undervoltage - Loss of Voltage	≤ 8.5
b. 4 kV Bus Undervoltage- Grid Degraded Voltage	≤ 600
18. Suction Transfer-Low Pit Level	
Nuclear Service Water Operation	N.A.

HOT STANDBY

LIMITING CONDITION FOR OPERATION

3.4.1.2 At least three of the reactor coolant loops listed below shall be OPERABLE and in operation:*

a. Reactor Coolant Loop A and its associated steam generator and reactor coolant pump,

b. Reactor Coolant Loop B and its associated steam generator and reactor coolant pump,

c. Reactor Coolant Loop C and its associated steam generator and reactor coolant pump, and

d. Reactor Coolant Loop D and its associated steam generator and reactor coolant pump.

APPLICABILITY: MODE 3.

ACTION:

a. With less than the above required reactor coolant loops OPERABLE, restore the required loops to OPERABLE status within 72 hours or be in HOT SHUTDOWN within the next 12 hours.

b. With less than the above required coolant loop in operation, restore the required loops to operation within 72 hours or open the Reactor Trip System breakers.

c. With no reactor coolant loops in operation, suspend all operations involving a reduction in boron concentration of the Reactor Coolant System and immediately initiate corrective action to return the required reactor coolant loops to operation.

SURVEILLANCE REQUIREMENTS

4.4.1.2.1 The required steam generators shall be determined OPERABLE by verifying secondary side water level to be greater than or equal to 12% at least once per 12 hours.

4.4.1.2.2 At least 3 reactor coolant loops shall be verified in operation and circulating reactor coolant at least once per 12 hours.

*All reactor coolant pumps may be deenergized for up to 1 hour provided: (1) no operations are permitted that would cause dilution of the Reactor Coolant System boron concentration, and (2) core outlet temperature is maintained at least 10°F below saturation temperature.

3/4.4.2 SAFETY VALVES

SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.4.2.1 A minimum of one pressurizer Code safety valve shall be OPERABLE with a lift setting of 2485 psig + 3%, -2% for Unit 1 and ± 1% for Unit 2.*

APPLICABILITY: MODES 4 and 5.

ACTION:

With no pressurizer Code safety valve OPERABLE, immediately suspend all operations involving positive reactivity changes and place an OPERABLE residual heat removal loop into operation in the shutdown cooling mode.

SURVEILLANCE REQUIREMENTS

4.4.2.1 No additional requirements other than those required by Specification 4.0.5.

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

LIMITING CONDITION FOR OPERATION

3.4.2.2 All pressurizer Code safety valves shall be OPERABLE with a lift setting of 2485 psig + 3%, -2% for Unit 1 and ± 1% for Unit 2.*

APPLICABILITY: MODES 1, 2, and 3.

ACTION:

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

SURVEILLANCE REQUIREMENTS

4.4.2.2 No additional requirements other than those required by Specification 4.0.5.

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

OPERATIONAL LEAKAGE

LIMITING CONDITION FOR OPERATION

3.4.6.2 Reactor Coolant System leakage shall be limited to:

a. No PRESSURE BOUNDARY LEAKAGE,

b. 1 gpm UNIDENTIFIED LEAKAGE,

c. 0.5 gpm total reactor-to-secondary leakage through all steam generators and 200 gallons per day through any one steam generator,

d. 10 gpm IDENTIFIED LEAKAGE from the Reactor Coolant System,

e. 40 gpm CONTROLLED LEAKAGE at a Reactor Coolant System pressure of 2235 ± 20 psig, and

f. 1 gpm leakage at a Reactor Coolant System pressure of 2235 ± 20 psig from any Reactor Coolant System Pressure Isolation Valve specified in Table 3.4-1.

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

ACTION:

a. With any PRESSURE BOUNDARY LEAKAGE, be in at least HOT STANDBY within 6 hours and in COLD SHUTDOWN within the following 30 hours.

b. With any Reactor Coolant System leakage greater than any one of the above limits, excluding PRESSURE BOUNDARY LEAKAGE and leakage from Reactor Coolant System Pressure Isolation Valves, reduce the leakage rate to within limits within 4 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

c. With any Reactor Coolant System Pressure Isolation Valve leakage greater than the above limit, isolate the high pressure portion of the affected system from the low pressure portion within 4 hours by use of at least two closed manual or deactivated automatic valves, or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

3/4.5 EMERGENCY CORE COOLING SYSTEMS

3/4.5.1 ACCUMULATORS

COLD LEG INJECTION

LIMITING CONDITION FOR OPERATION

3.5.1 Each cold leg injection accumulator shall be OPERABLE with:

a. The discharge isolation valve open,

b. A contained borated water volume of between 7704 and 8004 gallons,

c. A boron concentration of between 1900 and 2100 ppm,

d. A nitrogen cover-pressure of between 585 and 678 psig, and

e. A water level and pressure channel OPERABLE.

APPLICABILITY: MODES 1, 2, and 3*.

ACTION:

a. With one cold leg injection accumulator inoperable, except as a result of a closed isolation valve or boron concentration less than 1900 ppm, restore the inoperable accumulator to OPERABLE status within 1 hour or be in at least HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

b. With one cold leg injection accumulator inoperable due to the isolation valve being closed, either immediately open the isolation valve or be in at least HOT STANDBY within 6 hours and in HOT SHUTDOWN within the following 6 hours.

c. With one accumulator inoperable due to boron concentration less than 1900 ppm and:

   1) The volume weighted average boron concentration of the accumulators 1900 ppm or greater, restore the inoperable accumulator to OPERABLE status within 24 hours of the low boron determination or be in at least HOT STANDBY within the next 6 hours and reduce Reactor Coolant System pressure to less than 1000 psig within the following 6 hours.

   2) The volume weighted average boron concentration of the accumulators less than 1900 ppm but greater than 1800 ppm, restore the inoperable accumulator to OPERABLE status or return the volume weighted average boron concentration of the accumulators to greater than 1900 ppm and

*Reactor Coolant System pressure above 1000 psig.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

enter ACTION c.1 within 6 hours of the low boron determination or be in HOT STANDBY within the next 6 hours and reduce Reactor Coolant System pressure to less than 1000 psig within the following 6 hours.

3) The volume weighted average boron concentration of the accumulators 1800 ppm or less, return the volume weighted average boron concentration of the accumulators to greater than 1800 ppm and enter ACTION c.2 within 1 hour of the low boron determination or be in HOT STANDBY within the next 6 hours and reduce Reactor Coolant System pressure to less than 1000 psig within the following 6 hours.

SURVEILLANCE REQUIREMENTS

4.5.1 Each cold leg injection accumulator shall be demonstrated OPERABLE:

a. At least once per 12 hours by:

1) Verifying, by the absence of alarms, the contained borated water volume and nitrogen cover-pressure in the tanks, and

2) Verifying that each cold leg injection accumulator isolation valve is open.

b. At least once per 31 days and within 6 hours after each solution volume increase of greater than or equal to 75 gallons by verifying the boron concentration of the accumulator solution;

c. At least once per 31 days when the Reactor Coolant System pressure is above 2000 psig by verifying that power is removed from the isolation valve operators on Valves NI54A, NI65B, NI76A, and NI88B and that the respective circuit breakers are padlocked; and

d. At least once per 18 months by verifying that each cold leg injection accumulator isolation valve opens automatically under each of the following conditions:**

1) When an actual or a simulated Reactor Coolant System pressure signal exceeds the P-11 (Pressurizer Pressure Block of Safety Injection) Setpoint, and

2) Upon receipt of a Safety Injection test signal.

** This surveillance need not be performed until prior to entering HOT STANDBY following the Unit 1 refueling.

b) With a simulated or actual Reactor Coolant System pressure signal less than or equal to 660 psig the interlocks will cause the valves to automatically close.

2) A visual inspection of the containment sump and verifying that the subsystem suction inlets are not restricted by debris and that the sump components (trash racks, screens, etc.) show no evidence of structural distress or abnormal corrosion.

e. At least once per 18 months, during shutdown, by:**

1) Verifying that each automatic valve in the flow path actuates to its correct position on Safety Injection and Containment Sump Recirculation test signals, and

2) Verifying that each of the following pumps start automatically upon receipt of a Safety Injection test signal:

a) Centrifugal charging pump,

b) Safety Injection pump, and

c) Residual heat removal pump.

f. By verifying that each of the following pumps develops the indicated differential pressure when tested pursuant to Specification 4.0.5:

1) Centrifugal charging pump $\geq$ 2223 psid,

2) Safety Injection pump $\geq$ 1341 psid, and

3) Residual heat removal pump $\geq$ 165 psid.

g. By verifying the correct position of each electrical and/or mechanical stop for the following ECCS throttle valves:

1) Within 4 hours following completion of each valve stroking operation or maintenance on the valve when the ECCS subsystems are required to be OPERABLE, and

2) At least once per 18 months.

Centrifugal Charging Pump Injection Throttle Valve Number	Safety Injection Throttle Valve Number
NI-14	NI-164
NI-16	NI-166
NI-18	NI-168
NI-20	NI-170

**This surveillance need not be performed until prior to entering HOT SHUTDOWN following the Unit One first refueling.

h. By performing a flow balance test, during shutdown, following completion of modifications to the ECCS subsystems that alter the subsystem flow characteristics and verifying that:

1) For centrifugal charging pump lines, with a single pump running:

a) The sum of the injection line flow rates, excluding the highest flow rate, is greater than or equal to 345 gpm, and

b) The total pump flow rate is less than or equal to 560 gpm.

2) For Safety Injection pump lines, with a single pump running:

a) The sum of the injection line flow rates, excluding the highest flow rate, is greater than or equal to 450 gpm, and

b) The total pump flow rate is less than or equal to 675 gpm.

3) For residual heat removal pump lines, with a single pump running, the sum of the injection line flow rates is greater than or equal to 3648 gpm.

MAIN STEAM LINE ISOLATION VALVES

LIMITING CONDITION FOR OPERATION

3.7.1.4 Each main steam line isolation valve (MSLIV) shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTION:

MODE 1:

With one MSLIV inoperable but open, POWER OPERATION may continue provided the inoperable valve is restored to OPERABLE status within 4 hours; otherwise be in HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

MODES 2 and 3:

With one MSLIV inoperable, subsequent operation in MODE 2 or 3 may proceed provided the isolation valve is maintained closed. The provisions of Specification 3.0.4 are not applicable. Otherwise, be in HOT STANDBY within the next 6 hours and in HOT SHUTDOWN within the following 6 hours.

SURVEILLANCE REQUIREMENTS

4.7.1.4 Each MSLIV shall be demonstrated OPERABLE by verifying full closure within 8 seconds for Unit 1 and 5 seconds for Unit 2 when tested pursuant to Specification 4.0.5. The provisions of Specification 4.0.4 are not applicable for entry into MODE 3.

The specifications of this section provide assurance of fuel integrity during Condition I (Normal Operation) and II (Incidents of Moderate Frequency) events by: (1) maintaining the calculated DNBR in the core greater than or equal to design limit DNBR during normal operation and in short-term transients, and (2) limiting the fission gas release, fuel pellet temperature, and cladding mechanical properties to within assumed design criteria. In addition, limiting the peak linear power density during Condition I events provides assurance that the initial conditions assumed for the LOCA analyses are met and the ECCS acceptance criteria are not exceeded.

The definitions of certain hot channel and peaking factors as used in these specifications are as follows:

$F_Q(X,Y,Z)$ Heat Flux Hot Channel Factor, is defined as the maximum local heat flux on the surface of a fuel rod at core elevation Z divided by the average fuel rod heat flux, allowing for manufacturing tolerances on fuel pellets and rods;

$F\Delta H(X,Y)$ Nuclear Enthalpy Rise Hot Channel Factor, is defined as the ratio of the integral of linear power along the rod with the highest integrated power to the average rod power.

K(z) is defined as the normalized $F_Q(X,Y,Z)$ limit for a given core height.

3/4.2.1 AXIAL FLUX DIFFERENCE-Unit 1

The limits on AXIAL FLUX DIFFERENCE (AFD) specified in the CORE OPERATING LIMITS REPORT (COLR) ensure that the $F_Q(X,Y,Z)$ and the $F\Delta H(X,Y)$ limits are not exceeded during either normal operation or in the event of xenon redistribution following power changes. The AFD envelope specified in the COLR has been adjusted for measurement uncertainty.

3/4.2.2 and 3/4.2.3 HEAT FLUX HOT CHANNEL FACTOR, AND NUCLEAR ENTHALPY RISE HOT CHANNEL FACTOR (Unit 1)

The limits on heat flux hot channel factor, and nuclear enthalpy rise hot channel factor ensure that: (1) the design limits on peak local power density and minimum DNBR are not exceeded and (2) in the event of a LOCA the ECCS acceptance criteria are not exceeded. The peaking limits are specified in the CORE OPERATING LIMITS REPORT (COLR) per Specification 6.9.1.9.

The heat flux hot channel factor and nuclear enthalpy rise hot channel factor are each measurable but will normally only be determined periodically as specified in Specifications 4.2.2 and 4.2.3. This periodic surveillance is sufficient to insure that the limits are maintained provided:

HEAT FLUX HOT CHANNEL FACTOR, AND NUCLEAR ENTHALPY RISE HOT CHANNEL FACTOR (Unit 1) (Continued)

a. Control rods in a single group move together with no individual rod insertion differing by more than ± 12 steps, indicated, from the group demand position;

b. Control rod groups are sequenced with overlapping groups as described in Specification 3.1.3.6;

c. The control rod insertion limits of Specifications 3.1.3.5 and 3.1.3.6 are maintained; and

d. The axial power distribution, expressed in terms of AXIAL FLUX DIFFERENCE, is maintained within the limits.

$F\Delta H(X,Y)$ will be maintained within its limits provided Conditions a. through d. above are maintained.

The limits on the nuclear enthalpy rise hot channel factor, $F\Delta H(X,Y)$, are specified in the COLR as Maximum Allowable Radial Peaking limits, obtained by dividing the Maximum Allowable Total Peaking (MAP) limit by the axial peak [AXIAL(X,Y)] for location (X,Y). By definition, the Maximum Allowable Radial Peaking limits will, for Mark-BW fuel, result in a DNBR for the limiting transient that is equivalent to the DNBR calculated with a design $F\Delta H(X,Y)$ value of 1.50 and a limited reference axial power shape. For transition cores, MAP limits may be applied to both Mark-BW and optimized fuel types provided allowances for differences in DNBR are accounted for in the generation of MAP limits. The MAP limits specified in the COLR include allowances for mixed core DNBR effects. The relaxation of $F\Delta H(X,Y)$, as a function of THERMAL POWER allows changes in the radial power for all permissible control bank insertion limits. This relaxation is implemented by the application of the following factors:

$$k = [1 + (1/RRH)\ (1 - P)]$$

where k = power factor multiplier applied to the MAP limits
P = THERMAL POWER / RATED THERMAL POWER
RRH is given in the COLR

$FQ^M(X,Y,Z)$ and $F\Delta H^M(X,Y)$ are measured periodically, and comparisons to the allowable limit are made to provide reasonable assurance that the core is operating as designed and that the limiting criteria will not be exceeded for operation within the Technical Specification limits of Sections 2.2 (Limiting Safety Systems Settings), 3.1.3 (Movable Control Assemblies), 3.2.1 (Axial Flux Difference), and 3.2.4 (Quadrant Power Tilt Ratio). A peaking margin calculation is performed to provide a basis for decreasing the width of the AFD and $f(\Delta I)$ limits and for reducing THERMAL POWER.

HEAT FLUX HOT CHANNEL FACTOR, AND NUCLEAR ENTHALPY RISE HOT CHANNEL FACTOR (Unit 1) (Continued)

When an $FQ^M(X,Y,Z)$ measurement is obtained from a full core map in accordance with the surveillance requirements of Specification 4.2.2, no uncertainties are applied to the measured peak since the required uncertainties are included in the peaking limit. When $FQ^M(X,Y,Z)$ is measured for reasons other than meeting the requirements of Specification 4.2.2, the measured peak is increased by the radial-local peaking factor and allowances of 5% for measurement uncertainty and 3% for manufacturing tolerances.

When an $F\Delta H^M(X,Y)$ measurement is obtained from a full core map regardless of the reason, no uncertainties are applied to the measured peak since the required uncertainties are included in the peaking limit.

3/4.2.4 QUADRANT POWER TILT RATIO (Unit 1)

The QUADRANT POWER TILT RATIO limit assures that the radial power distribution satisfies the design values used in the power capability analysis. Radial power distribution measurements are made during STARTUP testing and periodically during power operation.

The limit of 1.02, at which corrective action is required, provides DNB and linear heat generation rate protection with x-y plane power tilts. A peaking increase that reflects a QUADRANT POWER TILT RATIO of 1.02 is included in the generation of the AFD limits.

The 2-hour time allowance for operation with a tilt condition greater than 1.02 but less than 1.09 is provided to allow identification and correction of a dropped or misaligned control rod. In the event such action does not correct the tilt, the margin for uncertainty on $F_Q(X,Y,Z)$ is reinstated by reducing the maximum allowed power by 3% for each percent of tilt in excess of 2%.

For purposes of monitoring QUADRANT POWER TILT RATIO when one excore detector is inoperable, the movable incore detectors are used to confirm that the normalized symmetric power distribution is consistent with the QUADRANT POWER TILT RATIO. The incore detector monitoring is done with a full incore flux map or two sets of four symmetric thimbles.

3/4.2.5 DNB PARAMETERS-(UNIT 1)

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 accident analyses. The limits are consistent with the initial FSAR assumptions and have been analytically demonstrated adequate to maintain a

3/4.2.5 DNB PARAMETERS-(UNIT 1) (Continued)

design limit DNBR throughout each analyzed transient. As noted on Figure 3.2-1, Reactor Coolant System flow rate and THERMAL POWER may be "traded off" against one another (i.e., a low measured Reactor Coolant System flow rate is acceptable if the THERMAL POWER is also low) to ensure that the calculated DNBR will not be below the design DNBR value. The relationship defined on Figure 3.2-1 remains valid as long as the limits placed on the nuclear enthalpy rise hot channel factor, $F\Delta H(X,Y)$ in Specification 3.2.3 are maintained. The indicated T_{avg} value and the indicated pressurizer pressure value correspond to analytical limits of 594.8°F and 2205.3 psig respectively, with allowance for measurement uncertainty. When Reactor Coolant System flow rate is measured, no additional allowances are necessary prior to comparison with the limits of Figure 3.2-1 since a measurement error of 2.1% for Reactor Coolant System total flow rate has been allowed for in determination of the design DNBR value.

The measurement error for Reactor Coolant System total flow rate is based upon performing a precision heat balance and using the result to calibrate the Reactor Coolant System flow rate indicators. Potential fouling of the feedwater venturi which might not be detected could bias the result from the precision heat balance in a nonconservative manner. Therefore, a penalty of 0.1% for undetected fouling of the feedwater venturi is included in Figure 3.2-1. Any fouling which might bias the Reactor Coolant System flow rate measurement greater than 0.1% can be detected by monitoring and trending various plant performance parameters. If detected, action shall be taken before performing subsequent precision heat balance measurements, i.e., either the effect of the fouling shall be quantified and compensated for in the Reactor Coolant System flow rate measurement or the venturi shall be cleaned to eliminate the fouling.

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. Indication instrumentation measurement uncertainties are accounted for in the limits provided in Table 3.2-1.

3/4.3.1 and 3/4.3.2 REACTOR TRIP SYSTEM and ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION

The OPERABILITY of the Reactor Trip System and the Engineered Safety Features Actuation System instrumentation and interlocks ensures that: (1) the associated ACTION and/or Reactor trip will be initiated when the parameter monitored by each channel or combination thereof reaches its Setpoint, (2) the specified coincidence logic and sufficient redundancy is maintained to permit a channel to be out-of-service for testing and maintenance, consistent with maintaining an appropriate level of reliability of the Reactor Protection and Engineered Safety Features instrumentation and (3) sufficient system functional capability is available from diverse parameters.

The OPERABILITY of these systems is required to provide the overall reliability, redundancy, and diversity assumed available in the facility design for the protection and mitigation of accident and transient conditions. The integrated operation of each of these systems is consistent with the assumptions used in the safety analyses. The Surveillance Requirements specified for these systems ensure that the overall system functional capability is maintained comparable to the original design standards. The periodic surveillance tests performed at the minimum frequencies are sufficient to demonstrate this capability.

Specified surveillance intervals and surveillance and maintenance outage times have been determined in accordance with WCAP-10271, "Evaluation of Surveillance Frequencies and Out of Service Times for the Reactor Protection Instrumentation System," and supplements to that report. Surveillance intervals and out of service times were determined based on maintaining an appropriate level of reliability of the Reactor Protection System and Engineered Safety Features instrumentation. (Implementation of quarterly testing of RTS is being postponed until after approval of a similar testing interval for ESFAS). The NRC Safety Evaluation Report for WCAP-10271 was provided in a letter dated February 21, 1985 from C. O. Thomas (NRC) to J. J. Sheppard (WOG-CP&L).

The Engineered Safety Features Actuation System Instrumentation Trip Setpoints specified in Table 3.3-4 are the nominal values at which the bistables are set for each functional unit. A Setpoint is considered to be adjusted consistent with the nominal value when the "as measured" Setpoint is within the band allowed for calibration accuracy.

To accommodate the instrument drift assumed to occur between operational tests and the accuracy to which Setpoints can be measured and calibrated. Allowable Values for the Setpoints have been specified in Table 3.3-4. Operation with Setpoints less conservative than the Trip Setpoint but within the Allowable Value is acceptable since an allowance has been made in the safety analysis to accommodate this error.

REACTOR TRIP SYSTEM and ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION (Continued)

The methodology to derive the Trip Setpoints is based upon combining all of the uncertainties in the channels. Inherent to the determination of the Trip Setpoints are the magnitudes of these channel uncertainties. Sensor and rack instrumentation utilized in these channels are expected to be capable of operating within the allowances of these uncertainty magnitudes. Rack drift in excess of the Allowable Value exhibits the behavior that the rack has not met its allowance. Being that there is a small statistical chance that this will happen, an infrequent excessive drift is expected. Rack or sensor drift, in excess of the allowance that is more than occasional, may be indicative of more serious problems and should warrant further investigation.

The measurement of response time at the specified frequencies provides assurance that the Reactor trip and the Engineered Safety Features actuation associated with each channel is completed within the time limit assumed in the safety analyses. No credit was taken in the analyses for those channels with response times indicated as not applicable. Response time may be demonstrated by any series of sequential, overlapping or total channel test measurements provided that such tests demonstrate the total channel response time as defined. Sensor response time verification may be demonstrated by either: (1) in place, onsite, or offsite test measurements, or (2) utilizing replacement sensors with certified response time.

The Engineered Safety Features Actuation System senses selected plant parameters and determines whether or not predetermined limits are being exceeded. If they are, the signals are combined into logic matrices sensitive to combinations indicative of various accidents, events, and transients. Once the required logic combination is completed, the system sends actuation signals to those Engineered Safety Features components whose aggregate function best serves the requirements of the condition. As an example, the following actions may be initiated by the Engineered Safety Features Actuation System to mitigate the consequences of a steam line break or loss-of-coolant accident: (1) Safety Injection pumps start and automatic valves position, (2) Reactor trip, (3) feedwater isolation, (4) startup of the emergency diesel generators, (5) containment

3/4.4.6.2 OPERATIONAL LEAKAGE

PRESSURE BOUNDARY LEAKAGE of any magnitude is unacceptable since it may be indicative of an impending gross failure of the pressure boundary. Therefore, the presence of any PRESSURE BOUNDARY LEAKAGE requires the unit to be promptly placed in COLD SHUTDOWN.

Industry experience has shown that while a limited amount of leakage is expected from the Reactor Coolant System, the unidentified portion of this leakage can be reduced to a threshold value of less than 1 gpm. This threshold value is sufficiently low to ensure early detection of additional leakage.

The total steam generator tube leakage limits of 0.5 gpm for all steam generators and 200 gpd maximum leakage into one steam generator ensures that the dosage contribution from the tube leakage will be limited to the applicable fraction of 10 CFR Part 100 dose guideline values in the event of any FSAR Chapter 15 transient or accident. The 0.5 gpm and 200 gpd limits bound the assumptions used in the analysis of these accidents. The 200 gpd leakage limit per steam generator also ensures that steam generator tube integrity is maintained in the event of a main steam line rupture or under LOCA conditions.

The 10 gpm IDENTIFIED LEAKAGE limitation provides allowance for a limited amount of leakage from known sources whose presence will not interfere with the detection of UNIDENTIFIED LEAKAGE by the Leakage Detection Systems.

The CONTROLLED LEAKAGE limitation restricts operation when the total flow supplied to the reactor coolant pump seals exceeds 40 gpm with the modulating valve in the supply line fully open at a nominal Reactor Coolant System pressure of 2235 psig. This limitation ensures that in the event of a LOCA, the safety injection flow will not be less than assumed in the safety analyses.

The 1 gpm leakage from any Reactor Coolant System pressure isolation valve is sufficiently low to ensure early detection of possible in-series check valve failure. It is apparent that when pressure isolation is provided by two in-series check valves and when failure of one valve in the pair can go undetected for a substantial length of time, verification of valve integrity is required. Since these valves are important in preventing overpressurization and rupture of the ECCS low pressure piping which could result in a LOCA that bypasses containment, these valves should be tested periodically to ensure low probability of gross failure.

The Surveillance Requirements for Reactor Coolant System pressure isolation valves provide added assurance of valve integrity thereby reducing the probability of gross valve failure and consequent intersystem LOCA. Leakage from the pressure isolation valve is IDENTIFIED LEAKAGE and will be considered as a portion of the allowed limit.

3/4.5.1 ACCUMULATORS

The OPERABILITY of each Reactor Coolant System accumulator ensures that a sufficient volume of borated water will be immediately forced into the reactor core through each of the cold legs from the cold leg injection accumulators and directly into the reactor vessel from the upper head injection accumulators in the event the Reactor Coolant System pressure falls below the pressure of the accumulators. This initial surge of water into the core provides the initial cooling mechanism during large pipe ruptures.

The limits on accumulator volume, boron concentration and pressure ensure that the assumptions used for accumulator injection in the safety analysis are met.

The allowed down time for the accumulators are variable based upon boron concentration to ensure that the reactor is shutdown following a LOCA and that any problems are corrected in a timely manner. Subcriticality is assured when boron concentration is above 1800 ppm, so additional down time is allowed when concentration is above 1800 ppm. A concentration of less than 1900 ppm in any single accumulator or as a volume weighted average may be indicative of a problem, such as valve leakage, but since reactor shutdown is assured, additional time is allowed to restore boron concentration in the accumulators.

The accumulator power operated isolation valves are considered to be "operating bypasses" in the context of IEEE Std. 279-1971, which requires that bypasses of a protective function be removed automatically whenever permissive conditions are not met. In addition, as these accumulator isolation valves fail to meet single failure criteria, removal of power to the valves is required.

The limits for operation with an accumulator inoperable for any reason except an isolation valve closed minimizes the time exposure of the plant to a LOCA event occurring concurrent with failure of an additional accumulator which may result in unacceptable peak cladding temperatures. If a closed isolation valve cannot be immediately opened, the full capability of one accumulator is not available and prompt action is required to place the reactor in a mode where this capability is not required.

SEMIANNUAL RADIOACTIVE EFFLUENT RELEASE REPORT (Continued)

The Radioactive Effluent Release Reports shall include a list and description of unplanned releases from the site to UNRESTRICTED AREAS of radioactive materials in gaseous and liquid effluents made during the reporting period.

The Radioactive Effluent Release Reports shall include any changes made during the reporting period to the PROCESS CONTROL PROGRAM (PCP) and to the OFFSITE DOSE CALCULATION MANUAL (ODCM), as well as a listing of new locations for dose calculations and/or environmental monitoring identified by the land use census pursuant to Specification 3.12.2.

MONTHLY OPERATING REPORTS

6.9.1.8 Routine reports of operating statistics and shutdown experience, including documentation of all challenges to the PORVs or safety valves, shall be submitted on a monthly basis to the NRC in accordance with 10 CFR 50.4, no later than the 15th of each month following the calendar month covered by the report.

CORE OPERATING LIMITS REPORT

6.9.1.9 Core operating limits shall be established and documented in the CORE OPERATING LIMITS REPORT before each reload cycle or any remaining part of a reload cycle for the following:

1. Moderator Temperature Coefficient BOL and EOL limits and 300 ppm surveillance limit for Specification 3/4.1.1.3,
2. Shutdown Bank Insertion Limit for Specification 3/4.1.3.5,
3. Control Bank Insertion Limits for Specification 3/4.1.3.6,
4. Axial Flux Difference Limits, target band*, and APL^{ND*} for Specification 3/4.2.1,
5. Heat Flux Hot Channel Factor, F_Q^{RTP}, K(Z), W(Z)**, APL^{ND**}, $F_Q^L(X,Y,Z)$ and $W(Z)_{BL}$** for Specification 3/4.2.2, and
6. Nuclear Enthalpy Rise Hot Channel Factor, $F\Delta H^{L***}(X,Y)$ or, $F_{\Delta H}^{RTP****}$, and Power Factor Multiplier, $MF\Delta H^{****}$, limits for Specification 3/4.2.3.

The analytical methods used to determine the core operating limits shall be those previously reviewed and approved by NRC in:

1. WCAP-9272-P-A, "WESTINGHOUSE RELOAD SAFETY EVALUATION METHODOLOGY," July 1985 (W Proprietary).

   (Methodology for Specifications 3.1.1.3 - Moderator Temperature Coefficient, 3.1.3.5 - Shutdown Bank Insertion Limit, 3.1.3.6 - Control Bank Insertion Limits, 3.2.1 - Axial Flux

*Reference 5 is not applicable to target band and APL^{ND}.
**References 4 and 5 are not applicable to W(Z), and APL^{ND}, and $W(Z)_{BL}$.
***Reference 1 is not applicable to $F\Delta H^L$.
****Reference 5 is not applicable to $F_{\Delta H}^{RTP}$ and $MF_{\Delta H}$.

CORE OPERATING LIMITS REPORT (Continued)

Difference, 3.2.2 - Heat Flux Hot Channel Factor, and 3.2.3 - Nuclear Enthalpy Rise Hot Channel Factor.)

2. WCAP-10216-P-A, "RELAXATION OF CONSTANT AXIAL OFFSET CONTROL FQ SURVEILLANCE TECHNICAL SPECIFICATION," June 1983 (W Proprietary).

   (Methodology for Specifications 3.2.1 - Axial Flux Difference (Relaxed Axial Offset Control) and 3.2.2 - Heat Flux Hot Channel Factor (W(Z) surveillance requirements for F_Q Methodology.)

3. WCAP-10266-P-A Rev. 2, "THE 1981 VERSION OF WESTINGHOUSE EVALUATION MODEL USING BASH CODE," March 1987, (W Proprietary).

   (Methodology for Specification 3.2.2 - Heat Flux Hot Channel Factor.)

4. BAW-10168PA, Rev. 1, "B&W Loss-of-Coolant Accident Evaluation Model for Recirculating Steam Generator Plants," January 1991 (B&W Proprietary).

   (Methodology for Specification 3.2.2 - Heat Flux Hot Channel Factor.)

5. DPC-NE-2011P-A, "Duke Power Company Nuclear Design Methodology for Core Operating Limits of Westinghouse Reactors," March, 1990 (DPC Proprietary).

   (Methodology for Specifications 3.1.3.5 - Shutdown Rod Insertion Limits, 3.1.3.6 - Control Bank Insertion Limits, 3.2.1 - Axial Flux Difference, 3.2.2 - Heat Flux Hot Channel Factor, and 3.2.3 - Nuclear Enthalpy Rise Hot Channel Factor.)

6. DPC-NE-3001P-A, "Multidimensional Reactor Transients and Safety Analysis Physics Parameter Methodology," November 1991 (DPC Proprietary).

   (Methodology for Specification 3.1.1.3 - Moderator Temperature Coefficient, 3.1.3.5 - Shutdown Rod Insertion Limits, 3.1.3.6 - Control Bank Insertion Limits, 3.2.1 - Axial Flux Difference, 3.2.2 - Heat Flux Hot Channel Factor, and 3.2.3 - Nuclear Enthalpy Rise Hot Channel Factor.)

7. DPC-NF-2010P-A, "Duke Power Company McGuire Nuclear Station Catawba Nuclear Station Nuclear Physics Methodology for Reload Design," June 1985 (DPC Proprietary).

   (Methodology for Specification 3.1.1.3 - Moderator Temperature Coefficient.)

8. DPC-NE-3002A, "FSAR Chapter 15 System Transient Analysis Methodology," November 1991.

   (Methodology used in the system thermal-hydraulic analyses which determine the core operating limits)

CORE OPERATING LIMITS REPORT (Continued)

9. DPC-NE-3000P-A, Rev. 1, "Thermal-Hydraulic Transient Analysis Methodology," November 1991.

   (Modeling used in the system thermal-hydraulic analyses)

The core operating limits shall be determined so that all applicable limits (e.g., fuel thermal-mechanical limits, core thermal-hydraulic limits, ECCS limits, nuclear limits such as shutdown margin, and transient and accident analysis limits) of the safety analysis are met.

The CORE OPERATING LIMITS REPORT, including any mid-cycle revisions or supplements thereto, shall be provided upon issuance, for each reload cycle, to the NRC in accordance with 10 CFR 50.4.

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

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NO. 101 TO FACILITY OPERATING LICENSE NPF-35

AND AMENDMENT NO. 95 TO FACILITY OPERATING LICENSE NPF-52

DUKE POWER COMPANY, ET AL.

CATAWBA NUCLEAR STATION, UNITS 1 AND 2

DOCKET NOS. 50-413 AND 50-414

1.0 INTRODUCTION

By letter dated April 13, 1992 (Reference 1), as supplemented July 8 and August 26, 1992, Duke Power Company, et al. (DPC or the licensee) submitted amendments to change the Catawba Nuclear Station, Units 1 and 2 Technical Specifications (TSs). The amendments consist of changes to the TSs for Catawba Unit 1 Cycle 7 reload. The April 13, 1992, submittal also contains changes to the Core Operating Limits Report (COLR), markups of the appropriate Final Safety Analysis Report (FSAR) chapters, and design information relative to Cycle 7 reload. The Catawba Unit 1 plant recently completed operating in Cycle 6 with a complete batch (1/3 core) of B&W Mark-BW 17x17 fuel design. Catawba Unit 1 Cycle 7 will include a second complete batch of B&W Mark-BW 17x17 fuel, resulting in a core that is 2/3 loaded with B&W Mark-BW 17x17 fuel. The use of Mark-BW fuel design in Catawba and the McGuire plants has been previously approved by the NRC via the topical reports BAW-10173-P-A, Revision 2 and BAW-10174-A, Revision 1, which were prepared by the B&W Fuel Company utilizing B&W's methods (References 2 and 3). The August 26, 1992, letter provided clarifying information that did not change the initial no significant hazards consideration determination.

The McGuire Cycle 8 was the first time DPC had performed reload safety analysis for its Westinghouse Units. The reload design and all the analysis for normal and off-normal operations will be carried out inhouse by DPC. The methods and analytical models used by DPC for Catawba Unit 1 Cycle 7 fuel assembly mechanical design, nuclear design, thermal-hydraulic analyses, and non-LOCA safety analysis have been approved by the NRC (References 4 to 7).

2.0 STAFF EVALUATION

2.1 Mechanical Design

The Cycle 7 reload will be the second time that the Mark-BW fuel will be used in Catawba Unit 1. This fuel is similar to the Westinghouse standard assembly design. The core consists of 72 fresh Mark-BW fuel assemblies, 49 Westinghouse optimized fuel assemblies and 72 Mark-BW fuel assemblies, for a

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total core loading of 193 Fuel Assemblies (FA). Out of 193 FAs, 121 are burned FAs. The unique features of the Mark-BW 17x17 design include the Zircaloy intermediate spacer grids, the spacer grid restraint system, and the use of Zircaloy grids with standard lattice design.

The mechanical analyses and thermal performance for the Mark-BW 17x17 design were performed by DPC with the methodology described in the approved topical report DPC-NE-2001-P-A, Revision 1 (Reference 8); and therefore, are acceptable.

3.0 FUEL SYSTEM DESIGN

3.1 Fuel Management

A general description of the Cycle 7 core is given in section 5.0. The Cycle 7 core uses a low-leakage fuel management scheme where previously burned assemblies are placed on the periphery and most of the fresh assemblies are located throughout the core interior in a pattern which minimizes power peaking. With this loading and a Cycle 6 endpoint of 350 effective full-power days (EFPD), the Cycle 7 reactive lifetime for full power operation is expected to be 350 EFPD. A comparison of Cycle 7 nominal characteristic physics parameters with those used in the safety analyses show that the latter are conservative in all cases.

3.2 Nuclear Design

The core physics parameters for Cycle 7 were generated by DPC with the PDQ07 and EPRI-NODE-P computer codes using the methodology described in the approved topical report DPC-2010-A (Reference 9). The Reactor Protection System setpoint limits and technical specification operating limits for the core were verified through analysis of the Cycle 7 nuclear design using methodology described in the approved topical report DPC-NE-2011-P-A (Reference 10).

3.3 Control Requirement

The value of the required shutdown margin varies throughout core life with the most restrictive value occurring at end of cycle and at hot zero power conditions. Sufficient boration capability and net available control element assembly (CEA) worth, including a minimum worth stuck CEA and appropriate calculation uncertainties, exist to meet all the shutdown margin requirements. These results were derived by approved methods and incorporate appropriate assumptions and are, therefore, acceptable.

4.0 THERMAL-HYDRAULIC DESIGN

The thermal performance of Cycle 7 fuel was analyzed using the NRC-approved methodology (Reference 8). The analyses included the power and burnup levels representative of the peak pin at each burnup interval, from the beginning of the cycle to the end of the cycle burnups. Based on this analysis, the internal pressure in the most limiting fuel rod will stay below the nominal reactor coolant system (RCS) pressure throughout the cycle. Because this satisfies Standard Review Plan (SRP) Section 4.2 criteria, the thermal design of the Cycle 7 core is acceptable.

The thermal-hydraulic analysis supporting Cycle 7 operation was performed by DPC with VIPRE-01 computer code and approved statistical core design (SCD) methodology (Reference 4). The SCD methodology is a technique that statistically combines uncertainties associated with the core statepoint parameters, code/model, and Critical Heat Flux (CHF) correlation to determine a statistical departure from nucleate boiling ratio (DNBR) limit. The uncertainties used in Reference 4 bound the uncertainties specifically calculated for Catawba Unit 1. The statistical DNBR limit for use with the BWCMV CHF correlation (Reference 11) in VIPRE-01 is determined to be 1.40. To provide design flexibility, a 10.7% margin is added to the statistical DNBR limit to yield a design DNBR limit of 1.55 for the generic Mark-BW and the Catawba Unit 1 Cycle 7 analyses. The reactor core safety limits for Catawba Unit 1 Cycle 7 were generated utilizing the BWCMV CHF correlation and the SCD methodology for a full core of Mark-BW assemblies and a radial enthalpy rise hot channel factor of 1.50.

The hydraulic compatibility of the Mark-BW fuel and the Westinghouse Optimized Fuel Assemblies (OFA) had been addressed in the approved topical report BAW-10173-P-A Revision 2 (Reference 2). The results of the hydraulic compatibility test indicated that the total pressure drop across the Mark-BW Fuel is 2.4% lower than the total pressure drop across the OFA fuel. The licensee approach to addressing the transition core penalty is presented in detail in Reference 3. The licensee determined a generic transition core penalty by modeling a conservative core configuration with one OFA assembly as the hot assembly located in a Mark-BW core. Bounding power shapes during normal and accident conditions were analyzed yielding a maximum DNBR penalty of 3.8% for OFA fuel. The licensee addressed the transition core penalty for OFA fuel by applying the 3.8% DNBR penalty against the 10.7% generic margin included in the design DNBR limit.

5.0 ACCIDENT ANALYSES

5.1 Non-LOCA Safety Analysis

The design basis events considered in the safety analyses are categorized into two groups: anticipated operational occurrences and postulated accidents (limiting faults). All events were reviewed by the licensee to account for the differences in the core physics parameters of the Mark-BW fuel and the changes to the Technical Specifications. The scope of the events considered is consistent with that addressed in the FSAR for Catawba. The evaluations considered the effects of mixed (transition) cores using Westinghouse and Mark-BW fuel.

The methods and results for the analyses of the Steam System Piping Failure, Rod Ejection and Dropped RCCA/RCCA bank transients, are documented in DPC topical report DPC-NE-3001 and follow-up correspondence from DPC which have been reviewed and found acceptable by the staff, (References 5 and 6). Analytical models and methodology for the statistically misaligned rod accident are provided in approved topical reports, (References 4, 7 and 9). For the generic and single events, a system thermal-hydraulic analysis was performed which bound both Catawba Units 1 and 2, and McGuire Units 1 and 2. Since a single set of generic analyses has been performed for these events, the results for Catawba are identical to those submitted in the approved

McGuire 2 Cycle 8 reload report, (Reference 12). The Catawba 1 Cycle 7 reload core physics parameters were reviewed with respect to the assumptions used in these analyses. The analysis and methodology for these events have been reviewed and found acceptable by the staff (References 5 and 9).

For the remaining FSAR thermal-hydraulic accident analyses sensitive to reload core physics parameters (e.g., LOCA), the current approved licensing bases are being retained. These bases have been reviewed and found acceptable by the staff (Reference 7). In addition, the post-LOCA subcriticality evaluation and the boron precipitation evaluation have been performed by DPC in the FSAR for Catawba (Reference 12). The Catawba Unit 1 Cycle 7 parameters have been reviewed with respect to the assumptions used in the subcriticality analysis.

The radiological consequences for the locked rotor, single rod withdrawal and rod ejection events, were reanalyzed due to differences between the Mark-BW fuel and the OFA fuel. The results, presented in section 8 of Reference 1, were reviewed and found acceptable by the staff as discussed below. Review by the staff of Catawba Unit 1 Cycle 7 reload parameters were found to be bounded by the accident analysis assumptions for all accidents which are sensitive to core physics parameters, and are therefore, acceptable.

5.2 LOCA Analyses

The LOCA analyses for Catawba Unit 1 transition cores with mixed Mark-BW and Westinghouse OFA assemblies and future cores with all Mark-BW fuel have been reviewed previously by the NRC (BAW-10174-A) and found acceptable.

5.3 Radiological Evaluation

In its analysis, the licensee determined that the radiological impact of two accidents, the rod ejection and the locked rotor events, could be impacted as a result of changes related to Cycle 7 operation. The licensee reanalyzed the potential radiological consequences arising from these events.

5.3.1 Locked Rotor

The locked rotor accident is analyzed by postulating an instantaneous seizure of a reactor coolant pump rotor, resulting in a rapid decrease in reactor coolant flow and a reactor trip. In the licensee's analysis, ten percent of the fuel was assumed to fail as a result of the accident. This is to be compared with the previously assumed FSAR value of a failed fuel percentage of 1% arising from a locked rotor.

In the staff's "Safety Evaluation Report related to the operation of Catawba Nuclear Station, Units 1 and 2" (NUREG-0954) and its Supplements, it was concluded that there is no fuel failure calculated to occur for this accident at Catawba.

In the FSAR for Catawba, the licensee indicated previously that 1% fuel failure could be expected for this event and that exclusion area boundary whole body and thyroid doses of 4.4E-01 and 3.6 rem, respectively, were calculated to occur. The licensee's April 13, 1992, submittal, reported whole body and thyroid doses at the exclusion area boundary of 0.253 and 25.5 rem,

respectively. However, these doses were calculated assuming a reduced primary to secondary leak rate of 0.5 gpm compared to the 1.0 gpm leak rate previously assumed. The reduced leak rage of 0.5 gpm was adopted so that the licensee's calculated potential offsite doses from a locked rotor event do not exceed the staff acceptance criterion that exclusion area boundary doses should be less than a small fraction (<10%) of Part 100 guideline values. Since the reduced TS allowable primary to secondary leakage value of 0.5 gpm reduces the calculated offsite radiological consequence from a locked rotor event to values which meet NRC regulatory criteria, the staff finds the changes proposed by the licensee related to the locked rotor event acceptable.

5.3.2 Rod Ejection

In analyzing the rod ejection accident, it is assumed that a mechanical failure of the control rod drive mechanism has occurred. Consequently, reactor coolant leaks to the containment and the control rod and control rod drive shaft would be moved to the fully withdrawn positions. As a result of this mechanical failure, a rapid positive reactivity insertion occurs as well as a primary system depressurization. An adverse core power distribution results with localized fuel damage.

In the staff's Safety Evaluation Report for Catawba (NUREG-0954), the staff used a value of 10% fuel failure as a result of the rod ejection accident. In performing its analysis contained in NUREG-0954, the staff calculated offsite doses via two pathways: 1) containment leakage of primary coolant from the ruptured drive mechanism, and 2) secondary system contaminated steam releases.

In the staff's SER analysis of this accident, a partition factor of 100 between the water and vapor phases in the steam generator was assumed. In addition, the staff's SER analysis of the radiological consequences of this event utilized the guidance of SRP 15.4.8 Appendix A and the recommendations of Regulatory Guide 1.77; this analysis indicated that thyroid doses from a postulated rod ejection accident from both secondary side leakage and containment leakage totalled about 7.9 rem. This assumes a failed fuel percentage of 10%. For purposes of this evaluation, the staff considered that a ratio of the assumed fuel failure rates and resultant thyroid doses would provide a suitable indication of calculated thyroid doses at the exclusion area boundary. Based on this technique, calculated exclusion area boundary thyroid doses are 39.5 rem. The licensee's projection of whole body dose is 0.28 rem. These values are well within the guideline values of 10 CFR 100. Consequently, the licensee has demonstrated that the radiological consequences of a rod ejection accident are within the acceptance criteria of Regulatory Guide 1.77 and SRP 15.4.8, and are acceptable.

5.3.3 Conclusions

Based on the foregoing, the staff concludes that the FSAR changes proposed by the licensee with respect to the radiological consequence analysis of the locked rotor and rod ejection accidents meet NRC regulatory criteria and are, therefore, acceptable.

6.0 TECHNICAL SPECIFICATION CHANGES

(1) Core Safety Limit (Figure 2.1-1a)

Figure 2.1-1a of the TS is revised to reflect the use of the BWCMV CHF correlation and the licensee's statistical core design (SCD) methodology with a 1.55 thermal design DNBR limit. The revised core safety limits are based on a full core of Mark-BW assemblies. The licensee addresses the transition core penalty for OFA fuel by applying a 3.8% DNBR penalty against the 10.7% generic margin included in the design DNBR limit. Since the BWCMV CHF correlation and the SCD methodology are based on the approved Topical Report DPC-NE-2004, we conclude that the revised core safety limits are acceptable.

(2) Revision to TS 2.2.1

The change to TS 2.2.1 will delete ACTION 2.2.1.b.1 and equation 2.2-1. ACTION 2.2.1.B.1 provides the option of declaring an instrumentation channel operable by the use of equation 2.2-1 when the Reactor Trip System Instrumentation (RTSI) or Interlock Setpoint (IS) is less conservative than the allowable value. This option requires the tabulation of the Total Allowance, the value Z, and the Sensor error terms in table 2.2-1. However, the deletion of this ACTION and equation 2.2-1 makes TS 2.2.1 more restrictive, in that the channel must be declared inoperable with the RTSI or the IS less conservative than the allowable value. This revision to TS 2.2.1 is acceptable.

(3) Changes to TS Table 2.2-1

The overtemperature and over power delta T trip function K values in TS Table 2.2-1 are revised to reflect the use of BWCMV CHF correlation and the statistical core design methodology with a 1.55 thermal design DNBR limit. In addition, an axial imbalance penalty, f2(delta I), is applied to (OP delta T) reactor trip.

The changes to delete the Power Range Neutron Flux Negative Rate reactor trip function from TS Tables 2.2-1, 3.3-1, 3.3-2, and 4.3-1 are acceptable, since it is no longer needed for the control rod drop event, when analyzed with the approved DPC methodology.

Also, the table is revised to delete the Total allowance (TA) column, the Z column, and the Sensor Error column from Table 2.2-1. This change is consistent with the proposed change to TS 2.2.1 and is acceptable.

(4) Changes to TS Table 3.1-1

TS Table 3.1-1 is revised to include all accident analyses that would require reevaluation in the event that one full-length Rod Cluster Control Assembly is inoperable. Deletion of large break LOCA (LBLOCA) analysis from TS Table 3.1-1 is acceptable since LBLOCA analysis does not take credit for any control rod insertion. This change is the same as that approved for McGuire Units 1 and 2. This change is acceptable.

(5) Changes to TS 3/4.2.2

The changes to TS 3/4.2.2 were made to provide surveillance requirements consistent with DPC methodology for core power distribution control and surveillance of power peaking as described in DPC-NE-2011PA. This change is acceptable.

(6) Changes to TS 3/4.2.2 and 3/4.2.3

TS 3/4.2.2 was revised to provide required actions and surveillance requirements consistent with DPC methodology for core power distribution control and surveillance of the nuclear enthalpy rise hot channel factor, as discussed in DPC-NE-2011PA. Also, the nomenclature is changed to reflect differences between DPC and the fuel vendor (B&W), and to clarify the surveillance requirements making them consistent with DPC's methods as described in DPC-NE-2011PA. Specification 3/4.2.3 was also revised to reflect the power peaking surveillance methods described in DPC-NE-2011PA. These changes are the same as those approved for McGuire 1. They have been appropriately described and justified in accordance with the approved DPC methodology and are, therefore, acceptable.

(7) Changes to TS 3/4.2.5

The change of the letter "a" to "b" in TS 3.2.5 ACTION item c.1.b connects the requirement of ACTION c.1.b to ACTION "b" instead of ACTION "a", which was incorrect. Therefore, it corrects a typographical error and does not represent an actual change to the requirements of TS 3/4.2.5. This change is acceptable.

(8) Changes to TS Table 3.3-2

The reactor trip on power range neutron flux negative rate is deleted. This is acceptable as explained in the changes to TS Table 2.2-1. The response times associated with the Resistance Temperature Detection (RTD) bypass system for the OT delta T and OP delta T are deleted, as is the footnote regarding the RTD bypass system. This is acceptable as the RTD bypass has been removed. Also, the neutron detector response time deletion which is applicable to the OT delta T trip is also deleted for the OP delta P trip due to the addition of the f2(delta I) function to the OP delta T trip. This is acceptable as explained in the changes to TS Table 2.2-1.

(9) Changes to TS 3/4.3.3.2

The changes to TS 3/4.3.3.2 include deletion of ACTION 3.3.2.b.1 and equation 2.2-1. These changes are consistent with the changes to TS 2.2.1, and the removal of the TA, Z, and S columns from tables 2.2-1 and 3.3-4. Deletion of ACTION 3.3.2.b.1 and equation 2.2-1 makes TS 3.3.2 more restrictive, in that the channel must be declared inoperable with the Engineered Safety Feature Actuation System (ESFAS) instrumentation or interlock setpoint less conservative than the allowable value. The staff finds the deletion of ACTION 3.3.2.b.1 and equation 2.2-1 to be acceptable as it improves the safe operation of the plant by reducing the complexity of the technical specifications.

(10) Changes to Table 3.3-4

Several categories of changes are made to table 3.3-4: (1) based on a reanalysis, the low steam line pressure setpoint for safety injection and main steam line isolation is increased from 725 psig to 775 psig and the allowable value of this trip function is changed from 694 psig to 744 psig, maintaining the same 31 psig allowance for rack uncertainties. The lead-lag controller for steam line pressure-low is deleted which eliminates spurious Engineered Safety Feature (ESF) actuation on minor pressure increases in the secondary system; (2) the TA, Z, and S columns are deleted from table 3.3-4 which is consistent with the removal of these items from table 2.2-1; and (3) the allowable values associated with the RTD bypass system for the feedwater isolation on Tavg-Low (item 5.c) and ESFAS P-12 interlock on Low-Low Tave (item 18.c) are deleted as a result of the RTD bypass system being removed. We have found the above changes to be acceptable.

(11) Change to TS 3.4.1.2

This specification is changed to require that three of the four loops be in operation for Mode 3. This restriction is imposed in order to make the specification consistent with the reanalysis of the uncontrolled bank withdrawal from subcritical or low power startup condition. The staff finds this change to be acceptable.

(12) Changes to TS 3/4.4.2.1 and TS 3/4.4.2.2

This modification changes the tolerance on the pressurizer safety valve lift setpoint from plus or minus 1% to +3% , -2% in all modes of operation. After verifying that the valves remain within tolerance over several cycles, this larger tolerance will enable reduction of work in a dangerous work environment by requiring only one valve to be tested per outage instead of three. The larger allowable deviation from the nominal lift setting is consistent with the licensing basis analyses. Three accident categories involving heat transfer mismatches, decrease in secondary heat removal, decrease in reactor coolant system flow rate and reactivity, and power distribution anomaly transients were analyzed by the licensee assuming a lift setpoint of 3 percent above the normal value. The analyses, which are the same as previously performed for McGuire and which used the approved methodology of topical reports DPC-NE-3001P (Reference 6) and DPC-NE-3002 (Reference 7), showed that the following peak RCS pressure acceptance criteria were met: 110% of design pressure for the feedline break and locked rotor transients and 120% of design pressure for the rod ejection transient. The amount by which the safety valve lift setpoint is allowed to drift downward is restricted to 2 percent of nominal in order to ensure that safety valve lift cannot preclude reactor trip on high pressurizer pressure. The licensee stated that reanalysis of departure from nucleate boiling (DNB) transients and the uncontrolled bank withdrawal at power and single rod withdrawal events showed that all acceptance criteria are met with the 2% downward setting. Based on meeting the acceptance criteria in the above analyses, the staff finds these changes to be acceptable.

(13) Changes to TS 3.5.1

This change raises the required average cold leg accumulator boron concentration in ACTIONS c.2 and c.3 from 1500 to 1800 ppm, and bases this average on all four accumulators instead of just the limiting three. Regardless of the break location, the contents of each accumulator will be emptied, either directly or indirectly into the containment sump. Therefore, calculating the volumetric average boron concentration based on all four cold leg accumulators is valid. The licensee has increased the volumetric average boron concentration from 1500 to 1800 ppm to ensure long-term subcriticality following a LOCA. Based on the licensee's analysis, the staff finds these changes to be acceptable.

(14) Changes to TS 4.5.2

The ECCS pump performance requirements in TS 4.5.2 (f) were modified by decreasing the centrifugal charging pump required head from 2380 to 2223 psid and the safety injection pump required head from 1420 to 1341 psid. Also, the ECCS delivered flow requirements in TS 4.5.2 (h) were modified by decreasing the centrifugal charging pump total flow rate from 565 to 560 gpm and increasing the safety injection total flow rate from 660 to 675 gpm. These revisions apply to Units 1 and 2. The licensee stated that these changes are consistent with revised pump vendor information and that margin is available to enable sufficient allowances for instrument errors and to permit reasonable test acceptance criteria. The pump performance at the new specification values is said to be sufficient to meet all acceptance criteria in both the current FSAR analyses, and in the Catawba 1 Cycle 7 reload. The staff, therefore, finds these changes to be acceptable.

(15) Change to TS 3/4.6.3, Table 3.6-2a

The proposed changes in Table 3.6-2a were related to isolation valve operation maximum response time. The licensee proposed that the numerical value of the stroke time of these valves be changed to NA partly on the basis that these valves do not receive a containment isolation signal. This information is inconsistent with the FSAR. Accordingly, the licensee withdrew this proposed change in its letter of August 26, 1992.

(16) Change to TS 3/4.7.1.4

As stated in the technical justification for the proposed revision to TS Table 3.3-4, the valve stroke time, when added to the applicable instrumentation delays, yields the overall ESF response time. This response time is input to the steam line break transient analysis. Analysis using the DPC approved SCD methodology shows this Condition IV transient does not violate the imposed Condition II acceptance criteria of no DNB. This change is acceptable.

(17) Changes to TS 6.9.1.9

The changes to TS 6.9.1.9 simply reflected the changes to the COLR due to the implementation of DPC core operating limit methodology.

The safety and control bank insertion limits were revised to reflect a minimum rod withdrawal limit of 222 steps and a maximum rod withdrawal limit of 230 steps. Analysis by Westinghouse showed that the various core physics parameters remained bounded by previous analysis. These changes are acceptable.

7.0 STATE CONSULTATION

In accordance with the Commission's regulations, the South Carolina State official was notified of the proposed issuance of the amendments. The State official had no comments.

8.0 ENVIRONMENTAL CONSIDERATION

The amendments change requirements with respect to installation or use of a facility component located within the restricted area as defined in 10 CFR Part 20 and change surveillance requirements. The NRC staff has determined that the amendments involve 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 the amendments involve no significant hazards consideration, and there has been no public comment on such finding (57 FR 32240 dated July 21, 1992). Accordingly, the amendments meet 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 the amendments.

9.0 CONCLUSION

The Commission has 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, (2) such activities will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendments will not be inimical to the common defense and security or to the health and safety of the public.

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