November 18, 1994

Mr. John L. Skolds
Senior Vice President, Nuclear Operations
South Carolina Electric & Gas Company
Virgil C. Summer Nuclear Station
Post Office Box 88
Jenkinsville, South Carolina 29065

Dear Mr. Skolds:

SUBJECT: ISSUANCE OF AMENDMENT NO. 119 TO FACILITY OPERATING LICENSE NO. NPF-12 REGARDING STEAM GENERATOR REPLACEMENT - VIRGIL C. SUMMER NUCLEAR STATION, UNIT NO. 1 (TAC NO. M88172)

The Nuclear Regulatory Commission has issued the enclosed Amendment No. 119 to Facility Operating License No. NPF-12 for the Virgil C. Summer Nuclear Station, Unit No. 1. The amendment changes the Technical Specifications in response to your application dated October 29, 1993, as supplemented March 11, 1994, May 18, 1994, September 20, 1994, and October 20, 1994.

The amendment changes the Technical Specifications to support the steam generator replacement. Specific changes are listed in the Safety Evaluation.

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

Sincerely,

George F. Wunder, Project Manager
Project Directorate II-1
Division of Reactor Projects - I/II
Office of Nuclear Reactor Regulation

Docket No. 50-395

Enclosures:
1. Amendment No. 119 to NPF-12
2. Safety Evaluation

cc w/enclosures:
See next page

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AMENDMENT NO. 119 TO FACILITY OPERATING LICENSE NO. NPF-12 - SUMMER, UNIT NO.1

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UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

SOUTH CAROLINA ELECTRIC & GAS COMPANY

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY

DOCKET NO. 50-395

VIRGIL C. SUMMER NUCLEAR STATION, UNIT NO. 1

AMENDMENT TO FACILITY OPERATING LICENSE

Amendment No. 119
License No. NPF-12

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

   A. The application for amendment by South Carolina Electric & Gas Company (the licensee), dated October 29, 1993, as supplemented March 11, 1994, May 18, 1994, September 20, 1994, and October 20, 1994, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations set forth in 10 CFR Chapter I;

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

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

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

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

2. Accordingly, the license is amended by 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-12 is hereby amended to read as follows:

(2) Technical Specifications and Environmental Protection Plan

The Technical Specifications contained in Appendix A, as revised through Amendment No. 119 , and the Environmental Protection Plan contained in Appendix B, are hereby incorporated in the license. South Carolina Electric & Gas Company shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

3. This amendment is effective as of its date of issuance and shall be implemented within 30 days of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

William H. Bateman, Director
Project Directorate II-1
Division of Reactor Projects - I/II
Office of Nuclear Reactor Regulation

Attachment:
Changes to the Technical
Specifications

Date of Issuance: November 18, 1994

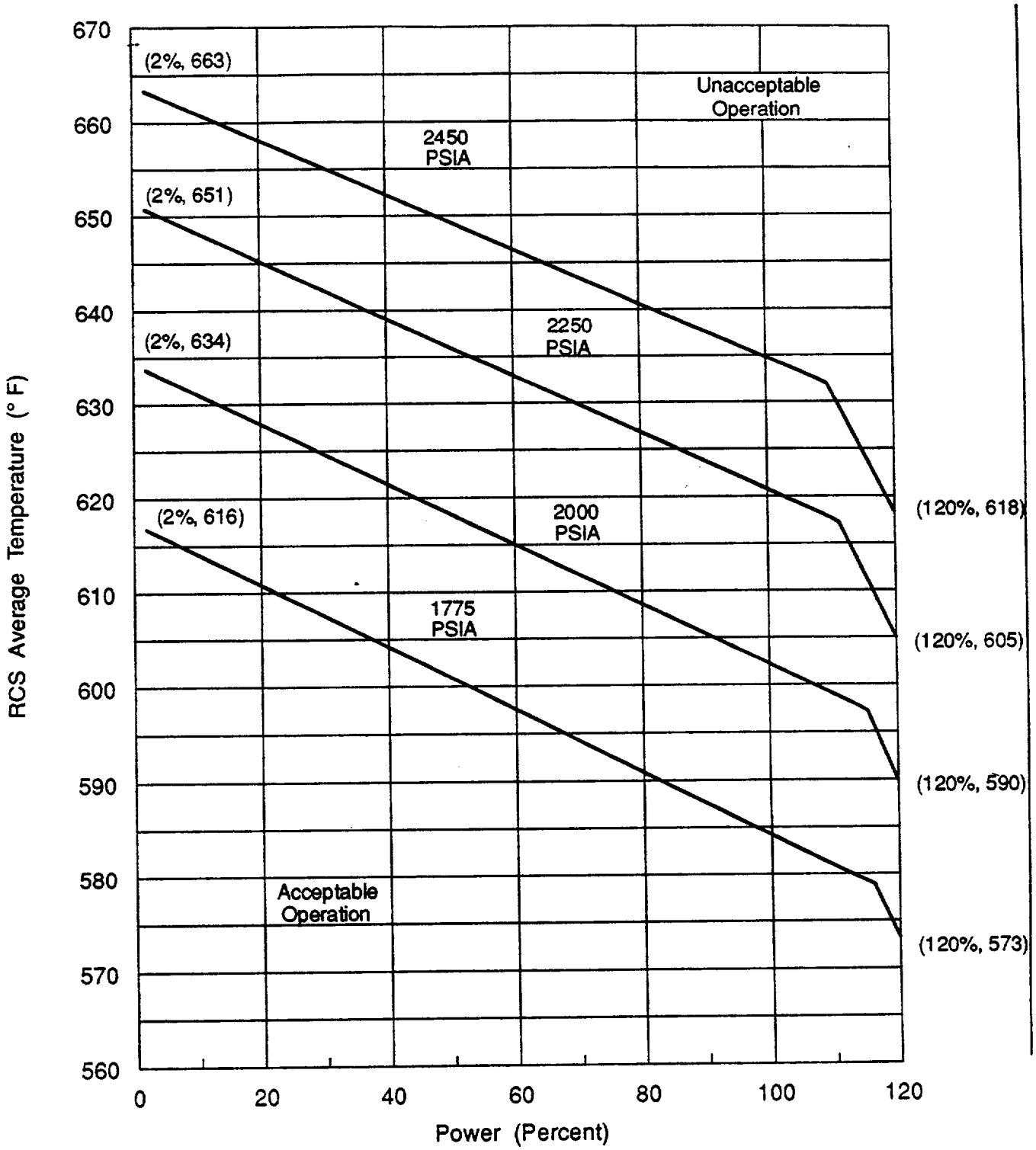
ATTACHMENT TO LICENSE AMENDMENT NO. 119

TO FACILITY OPERATING LICENSE NO. NPF-12

DOCKET NO. 50-395

Replace the following pages of the Appendix A Technical Specifications with the enclosed pages. The revised pages are indicated by marginal lines.

Remove Pages	Insert Pages
2-2	2-2
2-5	2-5
2-6	2-6
2-8	2-8
2-9	2-9
2-10	2-10
B 2-1	B 2-1
B 2-4	B 2-4
B 2-6	B 2-6
3/4 1.3a	3/4 1.3a
3/4 2-8	3/4 2-8
3/4 2-9	3/4 2-9
3/4 2-16	3/4 2-16
3/4 3-2	3/4 3-2
3/4 3-9	3/4 3-9
3/4 3-11	3/4 3-11
3/4 3-28	3/4 3-28
3/4 4-11	3/4 4-11
3/4 4-12	3/4 4-12
3/4 4-13	3/4 4-13
3/4 4-14	3/4 4-14
3/4 4-14a	3/4 4-14a
3/4 4-15	3/4 4-15
3/4 4-15a	3/4 4-15a
3/4 5-6	3/4 5-6
3/4 6-1	3/4 6-1
3/4 6-2	3/4 6-2
3/4 6-3	3/4 6-3
3/4 6-4	3/4 6-4
3/4 6-5	3/4 6-5
5-6	5-6
B 3/4 2-4	B 3/4 2-4
B 3/4 2-5	B 3/4 2-5
B 3/4 4-3	B 3/4 4-3
B 3/4 6-2	B 3/4 6-2



When operating in the reduced RTP region of Technical Specification 3.2.3 the restricted power level must be considered 100% RTP for this figure.

Figure 2.1-1
Reactor Core Safety Limits - Three Loop Operation

TABLE 2.2-1

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

	Functional Unit	Total Allowance (TA)	Z	S	Trip Setpoint	Allowable Value
1.	Manual Reactor Trip	Not Applicable	NA	NA	NA	NA
2.	Power Range, Neutron Flux					
	High Setpoint	7.5	4.56	0	≤109% of RTP	≤111.2% of RTP
	Low Setpoint	8.3	4.56	0	≤25% of RTP	≤27.2% of RTP
3.	Power Range, Neutron Flux High Positive Rate	1.6	0.5	0	≤5% of RTP with a time constant ≥2 seconds	≤6.3% of RTP with a time constant ≥2 seconds
4.	Deleted					
5.	Intermediate Range, Neutron Flux	17.0	8.4	0	≤25% of RTP	≤31% of RTP
6.	Source Range, Neutron Flux	17.0	10.0	0	$\leq 10^5$ cps	$\leq 1.4 \times 10^5$ cps
7.	Overtemperature ΔT	14.7	12.2	1.5 & 1.3**	See note 1	See note 2
8.	Overpower ΔT	5.1	2.0	1.5	See note 3	See note 4
9.	Pressurizer Pressure-Low	3.1	0.71	1.5	≥1870 psig	≥1859 psig
10.	Pressurizer Pressure-High	6.9	5.0	0.9	≤2380 psig	≤2391 psig
11.	Pressurizer Water Level-High	5.0	2.18	1.5	≤92% of instrument span	≤93.8% of instrument span
12.	Loss of Flow	2.5	1.48	.6	≥90% of loop design flow*	≥88.9% of loop design flow*

* Loop design flow = 94,500 gpm
RTP - RATED THERMAL POWER
** 1.5% span for Delta-T (RTDs) and 1.3% for Pressurizer Pressure

TABLE 2.2-1 (continued)

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

Functional Unit	Total Allowance (TA)	Z	S	Trip Setpoint	Allowable Value
13. Steam Generator Water Level Low-Low					
Barton Transmitter	7.0	5.1	1.7	≥27.0% of span	≥26.1% of span
Rosemount Transmitter	7.0	5.1	1.7	≥27.0% of span	≥25.7% of span
14. Steam/Feedwater Flow Mis-Match Coincident With	16.0	13.24	1.5/ 1.5	<40% of full steam flow at RTP	<42.5% of full steam flow at RTP
Steam Generator Water Level Low					
Barton Transmitter	7.0	5.1	1.7	≥27.0% of span	≥26.1% of span
Rosemount Transmitter	7.0	5.1	1.7	≥27.0% of span	≥25.7% of span
15. Undervoltage - Reactor Coolant Pump	2.1	1.28	0.23	≥4830 volts	≥4760
16. Underfrequency - Reactor Coolant Pumps	7.5	0	0.1	≥57.5 Hz	≥57.1 Hz
17. Turbine Trip					
A. Low Trip System Pressure	NA	NA	NA	≥800 psig	≥750 psig
B. Turbine Stop Valve Closure	NA	NA	NA	≥1% open	≥1% open

RTP - RATED THERMAL POWER

TABLE 2.2-1 (continued)
REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS
NOTATION

NOTE 1: OVERTEMPERATURE ΔT

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

Where:	ΔT	=	Measured ΔT by RTD Instrumentation
	ΔT_o	≤	Indicated ΔT at RATED THERMAL POWER
	K_1	≤	1.23
	K_2	≥	0.0292/°F
	$\frac{1+\tau_1 S}{1+\tau_2 S}$	=	The funtion generated by the lead-lag controller for T_{avg} dynamic compensation
	τ_1, τ_2	=	Time constants utilized in lead-lag controller for T_{avg}, $\tau_1 \geq 28$ secs., $\tau_2 \leq 4$ secs.
	T	=	Average temperature, °F
	T'	≤	Indicated T_{avg} at RATED THERMAL POWER, 572.0°F ≤ T' ≤ 587.4°F
	K_3	≥	0.00161/psi
	P	=	Pressurizer pressure, psig
	P'	≥	2235 psig, Nominal RCS operating pressure
	S	=	Laplace transform operator, sec^{-1}.

TABLE 2.2-1 (continued)
REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS
NOTATION (continued)

NOTE 1: (Continued)

and f_1 (ΔI) is a function of the indicated difference between top and bottom detectors of the power-range nuclear 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 percent and +6 percent f_1 (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 that the magnitude of $q_t - q_b$ exceeds -35 percent, the ΔT trip setpoint shall be automatically reduced by 2.46 percent of its value at RATED THERMAL POWER.

(iii) for each percent that the magnitude of $q_t - q_b$ exceeds +6 percent, the ΔT trip setpoint shall be automatically reduced by 3.29 percent of its value at RATED THERMAL POWER.

NOTE 2: The channel's maximum trip setpoint shall not exceed its computed trip point by more than 2.2 percent ΔT Span.

NOTE 3: OVERPOWER ΔT

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

Where:

ΔT	=	as defined in Note 1
ΔT_o	=	as defined in Note 1
K_4	$\leq$	1.078
K_5	$\geq$	0.02/°F for increasing average temperature and 0 for decreasing average temperature
$\frac{\tau_3 S}{1 + \tau_3 S}$	=	The function generated by the rate-lag controller for T_{avg} dynamic compensation

TABLE 2.2-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

NOTATION (Continued)

NOTE 3: (continued)

T_3	=	Time constant utilized in rate-lag controller for T_{avg}, $\tau_3 \geq 10$ secs.
K_6	$\geq$	0.00198/°F for $T > T''$ and $K_6 = 0$ for $T \leq T''$
T	=	as defined in Note 1
T''	$\leq$	Indicated T_{avg} at RATED THERMAL POWER, 572.0°F $\leq T'' \leq$ 587.4°F
S	=	as defined in Note 1

NOTE 4: The channel's maximum trip setpoint shall not exceed its computed trip point by more than 2.3 percent ΔT Span.

2.1 SAFETY LIMITS

BASES

2.1.1 REACTOR CORE

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. This relation has been developed to predict the DNB flux and the location of DNB for axially uniform and non-uniform heat flux distributions. The local DNB heat flux ratio (DNBR) defined as the ratio of the heat flux that would cause DNB at a particular core location to the local heat flux, is indicative of the margin to DNB.

The DNB design basis is as follows: there must be at least a 95 percent 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 correlation DNBR limit is established based on the entire applicable experimental data set such that there is a 95 percent probability with 95 percent 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 are considered statistically such that there is at least a 95 percent probability with 95 percent confidence level that the minimum DNBR for the limiting rod is greater than or equal to the DNBR limit. The uncertainties in the above plant parameters are used to determine the plant DNBR uncertainty. This DNBR uncertainty, combined with the correlation DNBR limit, establishes a design DNBR value which must be met in plant safety analyses using values of input parameters without uncertainties. In addition, margin has been maintained in the design by meeting safety analysis DNBR limits in performing safety analyses.

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.

REACTOR TRIP SYSTEM INSTRUMENTATION SETPOINTS (Continued)

The various reactor trip circuits automatically open the reactor trip breakers whenever a condition monitored by the Reactor Protection System reaches a preset or calculated level. In addition to redundant channels and trains, the design approach provides a Reactor Protection System which monitors numerous system variables, therefore, providing protection system functional diversity. The Reactor Protection System initiates a turbine trip signal whenever reactor trip is initiated. This prevents the reactivity insertion that would otherwise result from excessive reactor system cooldown and thus avoids unnecessary actuation of the Engineered Safety Features Actuation System.

Manual Reactor Trip

The Reactor Protection 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 percent 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 rod ejection from mid-power.

Intermediate and Source Range, Nuclear Flux

The Intermediate and Source Range, Nuclear Flux trips provide reactor core protection during reactor startup to mitigate the consequences of an

Pressurizer Pressure (Continued)

On decreasing power the low setpoint trip is automatically blocked by P-7 (a power level of approximately 10 percent of RATED THERMAL POWER with turbine impulse chamber pressure at approximately 10 percent of full power equivalent); and on increasing power, automatically reinstated by P-7.

The high setpoint trip functions in conjunction with the pressurizer relief and safety valves to protect the Reactor Coolant System against system overpressure.

Pressurizer Water Level

The pressurizer high water level trip is provided to prevent water relief through the pressurizer safety valves. On decreasing power the pressurizer high water level trip is automatically blocked by P-7 (a power level of approximately 10 percent of RATED THERMAL POWER with a turbine impulse chamber pressure at approximately 10 percent of full equivalent); and on increasing power, automatically reinstated by P-7.

Loss of Flow

The Loss of Flow trips provide core protection to prevent DNB by mitigating the consequences of a loss of flow resulting from the loss of one or more reactor coolant pumps.

On increasing power above P-7 (a power level of approximately 10 percent of RATED THERMAL POWER or a turbine impulse chamber pressure at approximately 10 percent of full power equivalent), an automatic reactor trip will occur if the flow in more than one loop drops below 90% of nominal full loop flow. Above P-8 (a power level of approximately 38 percent of RATED THERMAL POWER) an automatic reactor trip will occur if the flow in any single loop drops below 90 percent of nominal full loop flow. Conversely on decreasing power between P-8 and the P-7 an automatic reactor trip will occur on loss of flow in more than one loop and below P-7 the trip function is automatically blocked.

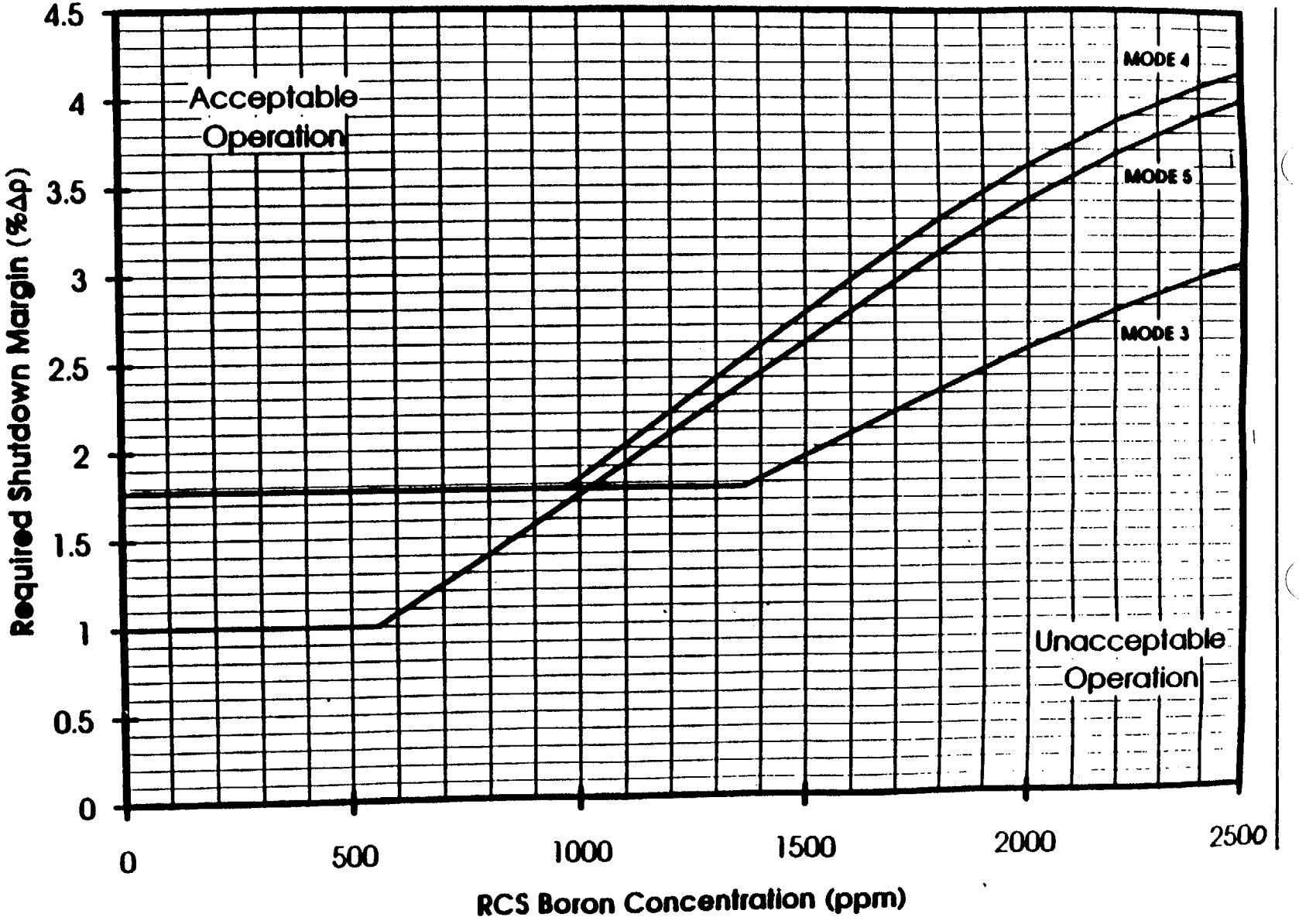
Steam Generator Water Level

The steam generator water level low-low trip protects the reactor from loss of heat sink in the event of a sustained steam/feedwater flow mismatch resulting from loss of normal feedwater. The specified setpoint provides allowances for starting delays of the auxiliary feedwater system.

Steam/Feedwater Flow Mismatch and Low Steam Generator Water Level

The steam/feedwater flow mismatch in coincidence with a steam generator low water level trip is not used in the transient and accident analyses but is included in Table 2.2-1 to ensure the functional capability of the specified trip settings and thereby enhance the overall reliability of the Reactor Protection System. This trip is redundant to the Steam Generator Water Level Low-Low trip. The Steam/Feedwater Flow Mismatch portion of this trip is activated when the steam flow exceeds the feedwater flow by greater than or equal to 40% of full steam flow at RTP. The Steam Generator Low Water level portion of the trip is activated when the water level drops below the low

FIGURE 3.1-3
REQUIRED SHUTDOWN MARGIN
(MODES 3, 4, AND 5)



3/4.2.3 RCS FLOW RATE AND NUCLEAR ENTHALPY RISE HOT CHANNEL FACTOR

LIMITING CONDITION FOR OPERATION

3.2.3 The combination of indicated Reactor Coolant System (RCS) total flow rate and R shall be maintained within the region of allowable operation as specified in the CORE OPERATING LIMITS REPORT (COLR) figure entitled RCS Total Flow Rate Versus R For Three Loop Operation.

Where:

a. $R = \dfrac{F^{N}_{\Delta H}}{F^{RTP}_{\Delta H}[1.0 + PF_{\Delta H}(1.0 - P)]}$,

b. $P = \dfrac{\text{THERMAL POWER}}{\text{RATED THERMAL POWER}}$,

c. $F^{N}_{\Delta H}$ = Measured values of $F^{N}_{\Delta H}$ obtained by using the movable incore detectors to obtain a power distribution map. The measured values of $F^{N}_{\Delta H}$ shall be used to calculate R since the RCS Total Flow Rate Versus R figure in the COLR includes measurement uncertainties of 2.1% (includes 0.1% for feedwater venturi fouling) for flow and 4% for incore measurement of $F^{N}_{\Delta H}$, and

d. $F^{RTP}_{\Delta H}$ = The $F^{N}_{\Delta H}$ limit at RATED THERMAL POWER specified in the COLR.

e. $PF_{\Delta H}$ = The Power Factor Multiplier specified in the COLR.

APPLICABILITY: MODE 1.

ACTION:

With the combination of RCS total flow rate and R outside the region of acceptable operation specified in the COLR:

a. Within 2 hours either:

1. Restore the combination of RCS total flow rate and R to within the above limits, or

2. 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.

b. Within 24 hours of initially being outside the above limits, verify through incore flux mapping and RCS total flow rate comparison that the combination of R and RCS total flow rate are restored to within the above limits, or reduce THERMAL POWER to less than 5% of RATED THERMAL POWER within the next 2 hours.

LIMITING CONDITION FOR OPERATION

ACTION: (Continued)

c. 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 items a.2. and/or b. above; subsequent POWER OPERATION may proceed provided that the combination of R and indicated RCS total flow rate are demonstrated, through incore flux mapping and RCS total flow rate comparison, to be within the region of acceptable operation specified in the COLR prior to exceeding the following THERMAL POWER levels:

1. A nominal 50% of RATED THERMAL POWER,

2. A nominal 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 The combination of indicated RCS total flow rate and R shall be determined to be within the region of acceptable operation specified in the COLR.

a. Prior to operation above 75% of RATED THERMAL POWER after each fuel loading, and

b. At least once per 31 Effective Full Power Days.

4.2.3.3 The indicated RCS total flow rate shall be verified to be within the region of acceptable operation specified in the COLR at least once per 12 hours when the most recently obtained value of R obtained per Specification 4.2.3.2, is assumed to exist.

4.2.3.4 The RCS total flow rate indicators shall be subjected to a CHANNEL CALIBRATION at least once per 18 months.

4.2.3.5 The RCS total flow rate shall be determined by heat balance measurement at $\geq$90% RATED THERMAL POWER at least once per 18 months.

TABLE 3.2-1

DNB PARAMETERS

PARAMETER	LIMITS	
	3 Loops In Operation	2 Loops In Operation
Indicated Reactor Coolant System T_{avg}	≤ 589.2°F	**
Indicated Pressurizer Pressure	≥ 2206 psig*	**

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

** These values left blank pending NRC approval of two-loop operation.

TABLE 3.3-1

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*	9
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.	Deleted					
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	0	1	3, 4 and 5	5
	C. Shutdown	2	1	2	3*, 4*, 5*	9
7.	Overtemperature ΔT					
	Three Loop Operation	3	2	2	1, 2	6#
	Two Loop Operation	****	****	****	****	****
8.	Overpower ΔT					
	Three Loop Operation	3	2	2	1, 2	6#
	Two Loop Operation	****	****	****	****	****
9.	Pressurizer Pressure-Low	3	2	2	1	6#
10.	Pressurizer Pressure--High	3	2	2	1, 2	6#

TABLE 3.3-2

REACTOR TRIP SYSTEM INSTRUMENTATION RESPONSE TIMES

FUNCTIONAL UNIT	RESPONSE TIME
1. Manual Reactor Trip	Not Applicable
2. Power Range, Neutron Flux	≤ 0.5 seconds(1)
3. Power Range, Neutron Flux, High Positive Rate	Not Applicable
4. Deleted	
5. Intermediate Range, Neutron Flux	Not Applicable
6. Source Range, Neutron Flux	Not Applicable
7. Overtemperature ΔT	≤ 8.5 seconds(1)(2)
8. Overpower ΔT	≤ 8.5 seconds(1)(2)
9. Pressurizer Pressure--Low	≤ 2.0 seconds
10. Pressurizer Pressure--High	≤ 2.0 seconds
11. Pressurizer Water Level--High	Not Applicable

(1) 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.
(2) The 8.5 second response time includes a 5.0 second delay for the RTDs mounted in thermowells.

TABLE 4.3-1

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(11)	N.A.	1, 2, 3*, 4*, 5*
2.	Power Range, Neutron Flux High Setpoint	S	D(2, 4), M(3, 4), Q(4, 6), R(4, 5)	Q	N.A.	N.A.	1, 2
	Low Setpoint	S	R(4)	S/U(1)	N.A.	N.A.	1###, 2
3.	Power Range, Neutron Flux High Positive Rate	N.A.	R(4)	Q	N.A.	N.A.	1, 2
4.	Deleted						
5.	Intermediate Range, Neutron Flux	S	R(4)	S/U(1),	N.A.	N.A.	1###, 2
6.	Source Range, Neutron Flux	S	R(4)	S/U(1),Q(9)	N.A.	N.A.	2##, 3, 4, 5
7.	Overtemperature ΔT	S	R	Q	N.A.	N.A.	1, 2
8.	Overpower ΔT	S	R	Q	N.A.	N.A.	1, 2
9.	Pressurizer Pressure--Low	S	R	Q	N.A.	N.A.	1
10.	Pressurizer Pressure--High	S	R	Q	N.A.	N.A.	1, 2
11.	Pressurizer Water Level--High	S	R	Q	N.A.	N.A.	1
12.	Loss of Flow	S	R	Q	N.A.	N.A.	1

TABLE 3.3-4 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

Functional Unit	Total Allowance (TA)	Z	S	Trip Setpoint	Allowable Value
5. TURBINE TRIP AND FEEDWATER ISOLATION					
a. Steam Generator Water Level - High-High					
Barton Transmitter	20.8	11.4	1.7	≤79.2% of span	≤81.0% of span
Rosemount Transmitter	20.8	12.4	1.7	≤79.2% of span	≤81.0% of span
6. EMERGENCY FEEDWATER					
a. Manual	NA	NA	NA	NA	NA
b. Automatic Actuation Logic	NA	NA	NA	NA	NA
c. Steam Generator Water Level - Low-Low					
Barton Transmitter	7.0	5.1	1.7	≥27.0% of span	≥26.1% of span
Rosemount Transmitter	7.0	5.1	1.7	≥27.0% of span	≥25.7% of span
d. & f. Undervoltage-ESF Bus				≥5760 Volts with a ≤0.25 second time delay	≥5652 Volts with a ≤0.275 second time delay
				≥6576 volts with a ≤3.0 second time delay	≥6511 Volts with a ≤3.3 second time delay

3/4.4.5 STEAM GENERATORS

LIMITING CONDITION FOR OPERATION

3.4.5 Each steam generator shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

With one or more steam generators inoperable, restore the inoperable generator(s) to OPERABLE status prior to increasing T_{avg} above 200°F.

SURVEILLANCE REQUIREMENTS

4.4.5.0 Each steam generator shall be demonstrated OPERABLE by performance of the following augmented inservice inspection program and the requirements of Specification 4.0.5.

4.4.5.1 Steam Generator Sample Selection and Inspection - Each steam generator shall be determined OPERABLE during shutdown by selecting and inspecting at least the minimum number of steam generators specified in Table 4.4-1.

4.4.5.2 Steam Generator Tube Sample Selection and Inspection - The steam generator tube minimum sample size, inspection result classification, and the corresponding action required shall be as specified in Table 4.4-2. The inservice inspection of steam generator tubes shall be performed at the frequencies specified in Specification 4.4.5.3 and the inspected tubes shall be verified acceptable per the acceptance criteria of Specification 4.4.5.4. The tubes selected for each inservice inspection shall include at least 3% of the total number of tubes in all steam generators. The tubes selected for these inspections shall be selected on a random basis except:

a. Where experience in similar plants with similar water chemistry indicates critical areas to be inspected, then at least 50% of the tubes inspected shall be from these critical areas.

b. The first sample of tubes selected for each inservice inspection (subsequent to the preservice inspection) of each steam generator shall include:

SURVEILLANCE REQUIREMENTS (Continued)

1. All nonplugged tubes that previously had detectable wall penetrations greater than 20%.

2. Tubes in those areas where experience has indicated potential problems.

3. A tube inspection (pursuant to Specification 4.4.5.4.a.8) shall be performed on each selected tube. If any selected tube does not permit the passage of the eddy current probe for a tube inspection, this shall be recorded and an adjacent tube shall be selected and subjected to a tube inspection.

c. The tubes selected as the second and third samples (if required by Table 4.4-2) during each inservice inspection may be subjected to a partial tube inspection provided:

1. The tubes selected for these samples include the tubes from those areas of the tube sheet array where tubes with imperfections were previously found.

2. The inspections include those portions of the tubes where imperfections were previously found.

The results of each sample inspection shall be classified into one of the following three categories:

Category	Inspection Results
C-1	Less than 5% of the total tubes inspected are degraded tubes and none of the inspected tubes are defective.
C-2	One or more tubes, but not more than 1% of the total tubes inspected are defective, or between 5% and 10% of the total tubes inspected are degraded tubes.
C-3	More than 10% of the total tubes inspected are degraded tubes or more than 1% of the inspected tubes are defective.

Note: In all inspections, previously degraded tubes must exhibit significant (greater than 10%) further wall penetrations to be included in the above percentage calculations.

4.4.5.3 Inspection Frequencies - The above required inservice inspections of steam generator tubes shall be performed at the following frequencies:

a. The first inservice inspection after the steam generator replacement shall be performed after at least 6 Effective Full Power Months from the time of the replacement but within 24 calendar months of initial criticality after the steam generator replacement. Subsequent inservice inspections shall be performed at intervals of not less than 12 nor more than 24 calendar months after the previous inspection. If two consecutive inspections following service under AVT conditions, not including the preservice inspection, result in all inspection results falling into the C-1 category or if two consecutive inspections demonstrate that previously observed degradation has not continued and no additional degradation has occurred, the inspection interval may be extended to a maximum of once per 40 months.

b. If the results of the inservice inspection of a steam generator conducted in accordance with Table 4.4-2 at 40 month intervals fall in Category C-3, the inspection frequency shall be increased to at least once per 20 months. The increase in inspection frequency shall apply until the subsequent inspections satisfy the criteria of Specification 4.4.5.3.a; the interval may then be extended to a maximum of once per 40 months.

c. Additional, unscheduled inservice inspections shall be performed on each steam generator in accordance with the first sample inspection specified in Table 4.4-2 during the shutdown subsequent to any of the following conditions:

   1. Primary-to-secondary tube leaks (not including leaks originating from tube-to-tube sheet welds) in excess of the limits of Specification 3.4.6.2.

   2. A seismic occurrence greater than the Operating Basis Earthquake.

   3. A loss-of-coolant accident requiring actuation of the engineered safeguards.

   4. A main steam line or feedwater line break.

4.4.5.4 Acceptance Criteria

a. As used in this Specification:

1. Imperfection means an exception to the dimensions, finish or contour of a tube from that required by fabrication drawings or specifications. Eddy-current testing indications below 20% of the nominal tube wall thickness, if detectable, may be considered as imperfections.

2. Degradation means a service-induced cracking, wastage, wear or general corrosion occurring on either inside or outside of a tube.

3. Degraded Tube means a tube containing imperfections greater than or equal to 20% of the nominal wall thickness caused by degradation.

4. % Degradation means the percentage of the tube wall thickness affected or removed by degradation.

5. Defect means an imperfection of such severity that it exceeds the plugging limit. A tube containing a defect is defective.

6. Tube Plugging Limit means the imperfection depth at or beyond which the tube shall be removed from service by plugging and is equal to 40% of the nominal tube wall thickness.

7. Unserviceable describes the condition of a tube if it leaks or contains a defect large enough to affect its structural integrity in the event of an Operating Basis Earthquake, a loss-of-coolant accident, or a steam line or feedwater line break as specified in 4.4.5.3.c, above.

8. Tube Inspection means an inspection of the steam generator tube from the point of entry (hot leg side) completely around the U-bend to the top support of the cold leg.

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9. Preservice Inspection means an inspection of the full length of each tube in each steam generator performed by eddy current techniques prior to service to establish a baseline condition of the tubing. This inspection shall be performed after the manufacturer's field hydrostatic test and prior to initial POWER OPERATION using the equipment and techniques expected to be used during subsequent inservice inspections.

b. The steam generator shall be determined OPERABLE after completing the corresponding actions (plug all tubes exceeding the plugging limit) required by Table 4.4-2.

4.4.5.5 Reports

a. Within 15 days following the completion of each inservice inspection of steam generator tubes, the number of tubes plugged in each steam generator shall be reported to the Commission in a Special Report pursuant to Specification 6.9.2.

b. The complete results of the steam generator tube inservice inspection shall be submitted to the Commission in a Special Report pursuant to Specification 6.9.2 within 12 months following the completion of the inspection. This Special Report shall include:

1. Number and extent of tubes inspected.

2. Location and percent of wall-thickness penetration for each indication of an imperfection.

3. Identification of tubes plugged.

c. Results of steam generator tube inspections which fall into Category C-3 and require prompt notification of the Commission shall be reported pursuant to 10 CFR 50.72(b)2(i) prior to resumption of plant operation. A report pursuant to 10 CFR 50.73(a)2(ii) shall be submitted to provide a description of investigations conducted to determine cause of the tube degradation and corrective measures taken to prevent recurrence.

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SURVEILLANCE REQUIREMENTS (Continued)

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 and with recirculation flow:

a) The sum of the injection line flow rates, excluding the highest flow rate, is greater than or equal to 338 gpm, and

b) The total pump flow rate is less than or equal to 688 gpm.

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

1) 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 3663 gpm.

3/4.6 CONTAINMENT SYSTEMS

3/4.6.1 PRIMARY CONTAINMENT

CONTAINMENT INTEGRITY

LIMITING CONDITION FOR OPERATION

3.6.1.1 Primary CONTAINMENT INTEGRITY shall be maintained.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

Without primary CONTAINMENT INTEGRITY, restore CONTAINMENT INTEGRITY within one hour or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.6.1.1 Primary CONTAINMENT INTEGRITY shall be demonstrated:

a. At least once per 31 days by verifying that all penetrations* not capable of being closed by OPERABLE containment automatic isolation valves and required to be closed during accident conditions are closed by valves, blind flanges, or deactivated automatic valves secured in their positions, except for valves that are open under administrative control as permitted by Specification 3.6.4.

b. By verifying that each containment air lock is in compliance with the requirements of Specification 3.6.1.3.

c. After each closing of each penetration subject to Type B testing, except the containment air locks, if opened following a Type A orB test, by leak rate testing the seal with gas at P_a (53.5 psig) and verifying that when the measured leakage rate for these seals is added to the leakage rates determined pursuant to Specification 4.6.1.2.d for all other Type B and C penetrations, the combined leakage rate is less than 0.60 L_a.

* Except valves, blind flanges, and deactivated automatic valves which are located inside the containment and are locked, sealed or otherwise secured in the closed position. These penetrations shall be verified closed during each COLD SHUTDOWN except that such verification need not be performed more often than once per 92 days.

CONTAINMENT LEAKAGE

LIMITING CONDITION FOR OPERATION

3.6.1.2. Containment leakage rates shall be limited to:

a. An overall integrated leakage rate of:

1. Less than or equal to L_a, 0.20 percent by weight of the containment air per 24 hours at P_a, 53.5 psig, or

2. Less than or equal to L_t, 0.10 percent by weight of the containment air per 24 hours at a reduced pressure of P_t, 26.8 psig.

b. A combined leakage rate of less than 0.60 L_a for all penetrations and valves subject to Type B and C tests, when pressurized to P_a.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

With either (a) the measured overall integrated containment leakage rate exceeding 0.75 L_a or 0.75 L_t, as applicable, or (b) with the measured combined leakage rate for all penetrations and valves subject to Types B and C tests exceeding 0.60 L_a, restore the overall integrated leakage rate to less than or equal to 0.75 L_a or less than or equal to 0.75 L_t, as applicable, and the combined leakage rate for all penetrations subject to Type B and C tests to less than 0.60 L_a prior to increasing the Reactor Coolant System temperature above 200°F.

SURVEILLANCE REQUIREMENTS

4.6.1.2 The containment leakage rates shall be demonstrated at the following test schedule and shall be determined in conformance with the criteria specified in Appendix J of 10 CFR 50 using the methods and provisions of ANSI N45.4-1972:

a. Three Type A tests (Overall Integrated Containment Leakage Rate) shall be conducted at 40 $\pm$10 month intervals* during shutdown at either P_a (53.5 psig) or at P_t (26.8 psig) during each 10-year service period. The third test of each set shall be conducted during the shutdown for the 10-year plant inservice inspection.

* A one time extension of the test interval is allowed for the third Type A test within the first 10-year service period, provided unit shutdown occurs no later than June 1, 1993 and performance of the Type A test occurs prior to unit restart following RF7.

SURVEILLANCE REQUIREMENTS (continued)

b. If any periodic Type A test fails to meet either 0.75 L_a or 0.75 L_t, the test schedule for subsequent Type A tests shall be reviewed and approved by the Commission. If two consecutive Type A tests fail to meet either 0.75 L_a or 0.75 L_t, a Type A test shall be performed at least every 18months until two consecutive Type A tests meet either 0.75 L_a or 0.75 L_t at which time the above test schedule may be resumed.

c. The accuracy of each Type A test shall be verified by a supplemental test which:

   1. Confirms the accuracy of the Type A test by verifying that the difference between supplemental and Type A test data is within 0.25 L_a, or 0.25 L_t.

   2. Has a duration sufficient to establish accurately the change in leakage rate between the Type A test and the supplemental test.

   3. Requires the quantity of gas injected into the containment or bled from the containment during the supplemental test to be equivalent to at least 25 percent of the total measured leakage at P_a (53.5 psig) or P_t (26.8psig).

d. Type B and C tests shall be conducted with gas at P_a (53.5psig) at intervals no greater than 24 months except for tests involving:

   1. Air locks.

   2. Purge supply and exhaust isolation valves with resilient material seals.

e. Purge supply and exhaust isolation valves with resilient material seals shall be tested and demonstrated OPERABLE per Surveillance Requirement 4.6.1.7.3.

f. Air locks shall be tested and demonstrated OPERABLE per Surveillance Requirement 4.6.1.3.

g. The provisions of Specification 4.0.2 are not applicable.

CONTAINMENT AIR LOCKS

LIMITING CONDITION FOR OPERATION

3.6.1.3 Each reactor building air lock shall be OPERABLE with:

a. Both doors closed except when the air lock is being used for normal transit entry and exit through the containment, then at least one air lock door shall be closed, and

b. An overall air lock leakage rate of less than or equal to 0.10 L_a at P_a, 53.5 psig.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

a. With one reactor building air lock door inoperable:

1. Maintain at least the OPERABLE air lock door closed and either restore the inoperable air lock door to OPERABLE status within 24 hours or lock the OPERABLE air lock door closed.

2. Operation may then continue until performance of the next required overall air lock leakage test provided that the OPERABLE air lock door is verified to be locked closed at least once per 31 days.

3. Otherwise, be in at least HOT STANDBY within the next six hours and in COLD SHUTDOWN within the following 30 hours.

4. The provisions of Specification 3.0.4 are not applicable.

b. With the reactor building air lock inoperable, except as the result of an inoperable air lock door, maintain at least one air lock door closed; restore the inoperable air lock to OPERABLE status within 24 hours or be in at least HOT STANDBY within the next six hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.6.1.3 Each reactor building air lock shall be demonstrated OPERABLE:

a. Within 72 hours following each closing, except when the air lock is being used for multiple entries, then at least once per 72 hours, by verifying that the seal leakage rate is less than or equal to 0.01 L_a when the volume between the door seals is pressurized to greater than or equal to 8.0 psig for at least 3 minutes.

b. By conducting overall air lock leakage tests at not less than P_a, 53.5 psig, and verifying the overall air lock leakage rate is within its limit:

   1. At least once per 6 months#, and

   2. Prior to establishing CONTAINMENT INTEGRITY when maintenance has been performed on the air lock that could affect the air lock sealing capability.*

c. At least once per six months by verifying that only one door in each air lock can be opened at a time.

d. At least once per 6 months#, by verifying that the seal leakage rate is less than or equal to 0.01 L_a when the volume between the handwheel shaft seals is pressurized to greater than or equal to 8.0 psig for at least 3 minutes.

The provisions of Specification 4.0.2 are not applicable.
* Exemption to Appendix J of 10CFR50.

5.3 REACTOR CORE

FUEL ASSEMBLIES

5.3.1 The core shall contain 157 fuel assemblies. Each fuel assembly shall consist of 264 Zircaloy-4 or ZIRLO(™) clad fuel rods with an initial composition of uranium dioxide with a maximum nominal enrichment of 5.0 weight percent U-235 as fuel material. Limited substitutions of Zircaloy-4, ZIRLO(™) and/or stainless steel filler rods for fuel rods, if justified by a cycle specific reload analysis using an NRC-approved methodology, may be used. Fuel assembly configurations shall be limited to those designs that have been analyzed with applicable NRC staff-approved codes and methods, and shown by tests or cycle-specific reload analyses to comply with all fuel safety design bases. Reload fuel shall contain sufficient integral fuel burnable absorbers such that the requirements of Specifications 5.6.1.1a.2 and 5.6.1.2.b are met. A limited number of lead test assemblies that have not completed representative testing may be placed in non-limiting core locations.

CONTROL ROD ASSEMBLIES

5.3.2 The reactor core shall contain 48 full length control rod assemblies. The full length control rod assemblies shall contain a nominal 142 inches of absorber material. The nominal values of absorber material shall be 80 percent silver, 15 percent indium and 5 percent cadmium. All control rods shall be clad with stainless steel tubing.

5.4 REACTOR COOLANT SYSTEM

DESIGN PRESSURE AND TEMPERATURE

5.4.1 The reactor coolant system is designed and shall be maintained:

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

b. For a pressure of 2485 psig, and

c. For a temperature of 650°F, except for the pressurizer which is 680°F.

VOLUME

5.4.2 The total water and steam volume of the reactor coolant system is 9914 ± 100 cubic feet at an indicated T_{avg} of 587.4°F.

5.5 METEOROLOGICAL TOWER LOCATION

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

HEAT FLUX HOT CHANNEL FACTOR and RCS FLOWRATE and NUCLEAR ENTHALPY RISE HOT CHANNEL FACTOR (Continued)

The hot channel factor $F_Q^M(z)$ is measured periodically and increased by a cycle and height dependent power factor appropriate to either RAOC or Base Load operation, W(z) or $W(z)_{BL}$, to provide assurance that the limit on the hot channel factor, $F_Q(z)$ is met. W(z) accounts for the effects of normal operation transients and was determined from expected power control maneuvers over the full range of burnup conditions in the core. $W(z)_{BL}$ accounts for the more restrictive operating limits allowed by Base Load operation which result in less severe transient values. The W(z) and $W(z)_{BL}$ functions described above for normal operation are specified in the CORE OPERATING LIMITS REPORT (COLR) per Specification 6.9.1.11.

When RCS flow rate and $F_{\Delta H}^N$ are measured, no additional allowances are necessary prior to comparison with the limits of the RCS Total Flow Rate Versus R figure in the COLR. Measurement errors of 2.1% for RCS total flow rate including 0.1% for feedwater venturi fouling and 4% for $F_{\Delta H}^N$ have been allowed for in determining the limits of the RCS Total Flow Rate Versus R figure in the COLR.

The 12-hour periodic surveillance of indicated RCS flow is sufficient to detect only flow degradation which could lead to operation outside the acceptable region of operation specified on the RCS Total Flow Rate Versus R figure in the COLR.

3/4.2.4 QUADRANT POWER TILT RATIO

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 limiting tilt of 1.025 can be tolerated before the margin for uncertainty in F_Q is depleted. The limit of 1.02 was selected to provide an allowance for the uncertainty associated with the indicated power tilt.

The two 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 is reinstated by reducing the maximum allowed power by 3 percent for each percent of tilt in excess of 1.0.

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 4 symmetric thimbles. These locations are C-8, E-5, E-11, H-3, H-13, L-5, L-11, N-8.

HEAT FLUX HOT CHANNEL FACTOR and RCS FLOWRATE and NUCLEAR ENTHALPY RISE HOT CHANNEL FACTOR (Continued)

3/4.2.5 DNB PARAMETERS

The limits on the DNB related parameters assure that each of the parameters are maintained within the normal steady state envelope of operation assumed in the transient and accident analyses. The limits are consistent with the initial FSAR assumptions and have been analytically demonstrated adequate to maintain a minimum DNBR in the core at or above the design limit throughout each analyzed transient. The maximum indicated Tavg limit of 589.2°F and the minimum indicated pressure limit of 2206 psig correspond to analytical limits of 591.4°F and 2185 psig respectively, read from control board indications.

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.

3/4.4.5 STEAM GENERATORS

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

The plant is expected to be operated in a manner such that the secondary coolant will be maintained within those chemistry limits found to result in negligible corrosion of the steam generator tubes. If the secondary coolant chemistry is not maintained within these limits, localized corrosion may likely result in stress corrosion cracking. The extent of cracking during plant operation would be limited by the limitation of steam generator tube leakage between the primary coolant system and the secondary coolant system (primary-to-secondary leakage = 500 gallons per day per steam generator). Cracks having a primary-to-secondary leakage less than this limit during operation will have an adequate margin of safety to withstand the loads imposed during normal operation and by postulated accidents. Operating plants have demonstrated that primary-to-secondary leakage of 500 gallons per day per steam generator can readily be detected by radiation monitors of steam generator blowdown. Leakage in excess of this limit will require plant shutdown and an unscheduled inspection, during which the leaking tubes will be located and plugged.

Wastage-type defects are unlikely with proper chemistry treatment of the secondary coolant. However, even if a defect should develop in service, it will be found during scheduled inservice steam generator tube examinations. Plugging will be required for all tubes with imperfections exceeding 40% of the tube nominal wall thickness. Steam generator tube inspections of operating plants have demonstrated the capability to reliably detect wastage-type degradation that has penetrated 20% of the original tube wall thickness.

Whenever the results of any steam generator tubing inservice inspection fall into Category C-3, these results will be promptly reported to the Commission pursuant to 10CFR50.72(b)2(i) prior to resumption of plant operation. Such cases will be considered by the Commission on a case-by-case basis and may result in a requirement for analysis, laboratory examinations, tests, additional eddy-current inspection, and revision of the Technical Specifications, if necessary.

3/4.6.1.4 INTERNAL PRESSURE

The limitations on reactor building internal pressure ensure that 1) the reactor building structure is prevented from exceeding its design negative pressure differential with respect to the outside atmosphere of 3.5 psig and 2) the reactor building peak pressure does not exceed the design pressure of 57psig during steam line break conditions.

The maximum peak pressure expected to be obtained from a steam line break event is 53.5 psig. The limit of 1.5 psig for initial positive containment pressure will limit the total pressure to 53.5 psig which is less than design pressure and is consistent with the accident analyses.

3/4.6.1.5 AIR TEMPERATURE

The limitations on reactor building average air temperature ensure that the overall containment average air temperature does not exceed the initial temperature condition assumed in the accident analysis for a steam line break accident.

3/4.6.1.6 REACTOR BUILDING STRUCTURAL INTEGRITY

This limitation ensures that the structural integrity of the containment will be maintained comparable to the original design standards for the life of the facility. Structural integrity is required to ensure that the containment will withstand the maximum pressure of 53.5psig in the event of a steam line break accident. The measurement of containment tendon lift off force, the tensile tests of the tendon wires, the visual examination of tendons, anchorages and exposed interior and exterior surfaces of the containment, and the Type A leakage test are sufficient to demonstrate this capability.

The tendon lift off forces are evaluated to ensure that 1) the rate of tendon force loss is within predicted limits, and 2) a minimum required prestress level exists in the containment. In order to assess the rate of force loss, the lift off force for a tendon is compared with the force predicted for the tendon times a reduction factor of 0.95. This resulting force is referred to as the 95% Base Value. The predicted tendon force is equal to the original stressing force minus losses due to elastic shortening of the tendon, stress relaxation of the tendon wires, and creep and shrinkage of the concrete. The 5% reduction on the predicted force is intended to compensate for both uncertainties in the prediction techniques for the losses and for inaccuracies in the lift-off force measurements.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NO. 119 TO FACILITY OPERATING LICENSE NO. NPF-12

SOUTH CAROLINA ELECTRIC & GAS COMPANY

SOUTH CAROLINA PUBLIC SERVICE AUTHORITY

VIRGIL C. SUMMER NUCLEAR STATION, UNIT NO. 1

DOCKET NO. 50-395

1.0 INTRODUCTION

By letter dated October 29, 1993, as supplemented March 11, 1994, and May 18, 1994, South Carolina Electric & Gas Company (the licensee) submitted a request for changes to the Virgil C. Summer Nuclear Station, Unit No. 1, (Summer Station or VCSNS) Technical Specifications (TS). A Correction Notice to the Federal Register notice was published on June 30, 1993 (59 FR 33795) correcting the amendment request date from October 29, 1993, to March 11, 1994.

The proposed changes support the installation of new steam generators at Summer Station. The changes involve:

(1) alterations to the core operating limits

(2) changes to various reactor trip setpoints

(3) deletion of the negative flux rate trip

(4) removal of references to specific correlations used in the departure from nucleate boiling (DNB) analyses

(5) changes to the steam/feedwater flow mismatch activation specification

(6) changes to shutdown limits

(7) changes to instrument uncertainty allowances

(8) a change to the methodology for reactor coolant system (RCS) flow determination

(9) modifications to DNB parameters

(10) a change to the engineered safety features actuation system setpoints for steam generator water levels

(11) removal of the F^* and L^* criteria

(I2) addition of a requirement for a first inservice inspection for the new steam generators

Because the new steam generators have a larger water mass and a greater heat transfer area than those originally installed at Summer Station, TS containing references to the maximum containment pressure following a steam line break and TS containing references to the total RCS volume will also change. In addition, a reference to RCS temperature is changed from a nominal value to an indicated value. The May 18, 1994, September 20, 1994, and October 20, 1994 submittals contain explanatory information and did not change the NRC staff's finding of no significant hazards consideration.

2.0 EVALUATION

2.1 Material Properties

Part of the licensee's October 29, 1993, submittal included proposed changes to the inspection and evaluation requirements for tubes repaired by sleeving. The licensee anticipates that the replacement steam generator tubes (alloy 690) will be substantially immune to the primary water stress corrosion cracking (PWSCC) problems encountered in the existing tubes (alloy 600). Removal of the sleeving evaluation and inspection criteria would leave only tube plugging as a corrective measure for any tubes that developed significant flaws in the future. A summary of the changes follows:

Page 3/4 4-11:
Deletes tube sample selection requirements for previously sleeved tubes.

Page 3/4 4-12:
Deletes sampling requirements for tubes evaluated to F^* or L^* criteria.

Page 3/4 4-13:
Clarifies minimum time interval to first inservice inspection after start-up of the new steam generators to occur after at least 6 effective full power months of operation.

Page 3/4 4-14:
Deletes tube sleeves as a repair option for defective tubes. Only plugging would be allowed. A defect requiring repair is defined as any imperfection greater than or equal to 40 percent of the nominal wall thickness.

Page 3/4 4-14a:
Deletes the definitions of "sleeve inspection" and "repaired tube" under the "Acceptance Criteria" (paragraph 4.4.5.4)

Page 3/4 4-15:
Deletes the definitions for F^* Distance, F^* Tube, L^* Distance, and L^* Tube under the acceptance criteria paragraph. Additionally, deletes the reference to a tube being operable after sleeve repair, and the requirement for submittal of report to the NRC identifying tubes repaired by sleeving. Tube plugging would still be reported under Specification 6.9.2.

Page 3/4 4-15a:
Deletes reporting requirements for F^* and L^* tubes.

Page B 3/4 4-3:
Under Bases section 3/4.4.5, references to repairing tubes found defective are deleted. References to L^* and F^* analyses are also deleted.

These changes to the TS refer either to sleeved tubes or to tubes in which defects had previously been found. Since the replacement generators are new, these specifications are not necessary. Therefore, the staff finds the proposed changes to the Summer Station TS, as specifically outlined above, to be acceptable. If the licensee determines that tube sleeving or other analyses like the ones deleted should be desired in the future, appropriate technical justification will be required to support any proposed TS change.

2.2 Piping Support and Seismic Considerations

In conjunction with the steam generator replacement project, the licensee has performed a reanalysis of portions of piping directly affected by the replacement of the steam generators. The affected piping is the nuclear steam supply system (NSSS) piping, consisting of the reactor coolant system; the balance-of-plant (BOP), consisting of the main steam system piping; the feedwater and emergency feedwater system piping; and the blowdown system piping from the steam generators to the respective reactor building penetrations. This reanalyses was used in a program that reduced the number of hydraulic snubbers and pipe-whip restraints that serve as seismic restraints. This reduction in snubbers was attained by using the following recent revisions in licensing requirements and design methodology:

- Generic Letter 87-11: This letter permits the elimination of arbitrary intermediate breaks in ASME Section III Class 1,2 and 3 piping.

- General Design Criterion 4 Rule Change: This change permits the application of leak-before-break technology to eliminate large postulated reactor coolant loop (RCL) pipe ruptures. This change was approved by the NRC for application at VCSNS on January 11, 1993.

- ASME Code Case N-411: This Code Case allows higher damping values for the seismic analysis of piping than those specified in Regulatory Guide 1.61 and has been endorsed by the staff in Regulatory Guide 1.84, Revision 29, with certain conditions applying. The principal such condition pertinent to VCSNS is that the increased damping values must be consistent with site-specific seismic spectra. The spectra used at VCSNS have been determined to be appropriate to permit the use of the damping values in this Code Case.

As a result of these revisions, the accident design transient conditions were revised from those used in the initial plant design. Using the revised design transients, the licensee reanalyzed the affected piping systems in accordance

with the Code of Record for this plant. For VCSNS, the design basis code for NSSS piping is the ASME Code, Section III, 1971 Edition through Winter 1971 Addenda. The fatigue reevaluations of these piping components were based on the 1977 Edition through 1979 Addenda. In addition, the new steam generators were designed to the 1986 Edition of the Code. The design basis code for BOP piping was ASME Code, Section III, 1971 Edition through Summer 1973 Addenda. These editions have all been endorsed by the staff in 10 CFR 50.55a, and are, therefore, acceptable.

In a letter dated May 18, 1994, the licensee submitted additional information regarding the results of the piping reanalyses. Based on the revised requirements, the dynamic effects of pipe breaks in the RCL were excluded from the revised design basis; however, the effects of pipe breaks at RCL branch piping nozzles were still considered. The reevaluation of the NSSS and BOP piping, components, and containment penetrations was performed under the same loading combinations as stated in the VCSNS Final Safety Analysis Report (FSAR). The number of snubbers on the steam generators were thus reduced from 15 to 6. The pressurizer surge line that is attached to the hot leg was also reanalyzed for thermal stratification due to the revised RCL hot leg temperatures. The snubbers on the surge line were thus reduced from 4 to 1. The number of snubbers decreased from 83 to 50, while the number of rigid restraints increased from 53 to 79. The number of pipe-whip restraints also decreased from 47 to 36. We find this to be acceptable.

The licensee performed a structural reevaluation of the reactor vessel, the reactor internals, the inlet and outlet nozzles, and the control rod drive mechanism housings due to the revised operating conditions and transient loadings. The Code of Record for the reactor vessel is the 1971 Edition of the ASME Code, Section III. The vessel and head flanges and the closure studs were found to have increased cumulative usage factors, but were shown to remain well within the ASME Code acceptance limit. The internal hydraulic lift forces were also reevaluated and were found to have minimal effects on the reactor internals. All components were found to satisfy the respective ASME Code allowable.

Structural evaluations of the new steam generators, the pressurizer, the reactor coolant pumps, and the control rod drive mechanisms were performed for the revised operating conditions and new design transients. These components were also found to satisfy the respective ASME Code allowable.

The staff has reviewed the mechanical and seismic aspects of the proposed steam generator replacement project and finds them to be acceptable.

2.3 Reactor Systems Considerations

In the design analysis for the replacement steam generators, the licensee used the engineered safeguards design rating of 2900 MWt core power in its safety evaluation to support the replacement stem generators (RSGs). This conservatively bounds the current licensed core power of 2775 MWt. In order to allow more flexible plant operation, a range of full power nominal T_{AVE} values from a maximum value of 587.4 °F to a minimum of 572.0 °F has been

factored into the analysis. Thermal design flow will be reduced to 92,600 gpm/loop, to support up to 10 percent steam generator tube plugging.

Core Safety Limits

The Reactor Core Safety Limits specified in TS Figure 2.1-1 show the loci of points of thermal power, RCS pressure, and average RCS temperature for which the minimum DNB ratio (DNBR) is not less than the safety analysis limit. This figure shows that the fuel centerline temperature remains below melting, and the average enthalpy in the hot leg is less than the enthalpy of saturated liquid. The changes to Figure 2.1-1 proposed by the licensee reflect a higher core power level (i.e., 2900 MWt) and other bounding parameters used in the safety analyses. The methodology used for developing the proposed core safety limits has been previously reviewed and approved by the NRC staff; therefore, these changes are acceptable.

Reactor Trip Setpoints

The following reactor trip setpoint limits, specified in TS Table 2.2-1, are affected by the RSG and revised operating conditions: (1) overtemperature delta T (OTΔT), (2) overpower delta T (OPΔT), (3) high pressurizer pressure, (4) low-low steam generator water level, (5) steam/feedwater flow mismatch coincident with steam generator low level, and (6) loss of flow.

The OTΔT trip function provides sufficient core protection to preclude DNB over a range of transient conditions. The effects of the RSG, higher power rating, a larger range of average RCS temperature, and other parameter changes are factored into the revised setpoints. The methodology used in developing these variable setpoints is the same as that used for the current TS setpoints. The revised OTΔT setpoint has been demonstrated acceptable in the licensee's new analysis for an uncontrolled RCCA withdrawal at power and accidental depressurization of the RCS in which the OTΔT provides primary reactor protection function. The results of these transients meet acceptance criteria established in the NRC Standard Review Plans for the events.

The OPΔT trip function provides assurance of fuel integrity under all possible overpower conditions. The OPΔT serves as a back-up to the high neutron flux trip. The effects of the RSG higher power rating, a range of average RCS temperature and other parameter changes are factored into the revised setpoints using the methodology previously reviewed and approved by the NRC staff.

The high pressurizer pressure trip function, in conjunction with pressurizer relief and safety valves, provides protection against RCS overpressure. The revised high pressurizer pressure trip setpoint has been demonstrated acceptable in the licensee's new analysis for a loss of load transient in which the high pressurizer pressure trip provides the primary reactor protection function. The results of the transient meet acceptance criteria established in the NRC Standard Review Plan for the event.

The low-low steam generator water level trip function specified in TS Table 2.2-1 and Table 3.3-4 protect the reactor from loss of heat sink and starts

the emergency feedwater system. The revised low-low steam generator level trip setpoints have been developed with consideration for the affects of the RSG and other parameter changes. The new setpoints have been demonstrated to be acceptable in the licensee's new analysis for a loss of normal feedwater transient in which the low-low steam generator level trip provides the primary reactor protection function. The results of the transient meet acceptance criteria established in the NRC Standard Review Plan for the event.

The steam/feedwater flow mismatch coincident with steam generator water level low trip is used to prevent loss of heat sink and serves as a backup to the low-low steam generator level trip. This trip function is not used in the transient and accident analyses, but it is included in TS Table 2.2-1 to enhance the overall reliability of the reactor protection system. The setpoints have been developed with consideration for the effects of the RSG and other parameter changes.

The loss of flow reactor trip provides protection to preclude DNB during a loss of RCS flow transient. The trip setpoints have been slightly reduced in terms of actual flow rates. The revised trip setpoints have been demonstrated acceptable in the licensee's new analysis for a loss of flow transient in which the loss of flow trip provides the primary reactor protection function. The results of the transient meet acceptance criteria established in the NRC Standard Review Plan for the event.

The licensee requested that the TS associated with the power range neutron flux high negative rate in Table 2.2-1, 3.3-1, 3.3-2, and 4.3-1 be deleted, because this reactor trip function is not credited in the dropped rod analysis. The staff considers this acceptable because the trip is not needed for a safety function and its removal reduces the probability of spurious reactor trips.

Shutdown Margin

TS Figure 3.1-3 defines the shutdown margin requirement as a function of average RCS boron concentration during Modes 3, 4, and 5 of reactor operation. In these modes, the most limiting event is a boron dilution event. The licensee has performed a new analysis for a boron dilution event using the revised shutdown margin requirement. The results of the analysis demonstrate that the time available between the time an alarm announces an unplanned moderator dilution and the time of loss of shutdown margin is sufficient for the operator to take action to terminate the event. The staff considers the proposed change of TS Figure 3.1-3 acceptable.

RCS Flow Rate and Nuclear Enthalpy Rise Hot Channel Factor

Technical Specification 3.2.3 has been modified to include a 0.1 percent uncertainty measurement into the calculation of the nuclear enthalpy rise hot channel factor to account for feedwater venturi fouling. The staff considers this to be conservative and acceptable. Specification 4.2.3.5 has been revised to determine RCS total flow rate once per 18 months by heat balance at $\geq$ 90 percent rated thermal power.

DNB Parameters

Table 3.2-1 has been revised to include indication uncertainties for average RCS temperature and pressurizer pressure in the specified limits for DNB. The staff finds this acceptable.

High-High Steam Generator Level

Table 3.3-4 specified the high-high steam generator level setpoints for turbine trip and feedwater isolation for turbine and main steam line protection. This table has been revised to reflect the RSG design. The staff finds the proposed changes conservative and acceptable.

Total RCS Water/Steam Volume

The total RCS water/steam volume specified in TS 5.4.2 has been revised to incorporate the changes affected by RSG. This is acceptable.

Loss-of-Coolant Accident Analyses

The licensee provided reanalyses of the VCSNS large break (LB) and small break (SB) loss-of-coolant accident (LOCA) licensing basis analyses in support of the steam generator replacement effort. Analysis assumptions reflect performance parameters appropriate to VCSNS with Westinghouse Delta 75 replacement steam generators.

Large Break LOCA Analyses

In the October 1993, submittal the licensee provided the results of a limited spectrum of LBLOCA analyses that were performed to account for the VCSNS plant design with the replacement steam generators. The analyses were performed using the Westinghouse 1981 Evaluation Model with BASH (WCAP-10266-P-A, Rev. 2, 1987), which has been approved by the NRC for licensing applications and is applicable to VCSNS.

Sensitivity Studies and Spectrum Analysis

The licensee has referenced previous studies to support its conclusion that the limiting type and location of a large break continues to be a double-ended cold leg guillotine (DECLG) rupture. The analyses assume the reactor core consists of Westinghouse VANTAGE+ (ZIRLO) fuel, with integral fuel burnable absorbers (IFBA). A special mixed core penalty due to the presence of IFBA rods was not assessed in the analyses, because of the geometric likeness of IFBA rods to non-IFBA fuel rods. The analyses also take credit for performance of high pressure injection (HPI) pumps that are assumed to be capable of delivering a minimum flow of 321 gallons-per-minute (gpm) (excluding the flow from the pump demonstrated to have the highest flow).

The licensee provided the following sensitivity/spectrum analysis cases to identify and quantify the worst case:

1. DECLG, C_D = 0.8, with minimum safety injection (one SI train)

2. DECLG, C_D = 0.6, with minimum SI

3. DECLG, C_D = 0.4, with minimum SI

4. DECLG, C_D = 0.4, with maximum SI (no SI single failure)

5. DECLG, C_D = 0.4, with minimum SI and IFBA fuel

Results of Licensing Basis Large Break Loss-of-Coolant Analysis

The last case (above) was identified as the worst LBLOCA case. In addition to the assumptions identified above, this case also assumed 102 percent of the Summer Station licensed core power level of 2775 MWt, a thermal design flow of 277,800 gpm, a vessel average temperature range of 572°F to 587.4°F, a hot channel enthalpy rise factor ($F_{\Delta H}$) of 1.62, a total core peaking factor (F_Q) of 2.45, and 10 percent uniform steam generator tube plugging.

The calculated peak cladding temperature is 2003°F, the calculated maximum local metal/water reaction is 6.02 percent, and the calculated core-wide metal/water reaction is less than 1 percent. These results are within the criteria specified in 10 CFR 50.46(b) (1 through 3) of 2200°F, 17 percent, and 1 percent, respectively. The results assure that the core will remain amenable to cooling, as required by 10 CFR 50.46(b)(4). The licensee reported that the time of emergency core coolant system (ECCS) hot leg switchover was determined by analysis to be within 8 hours. This, combined with the Summer Station ECCS design, as approved, assures continued conformance with the long-term cooling requirement of 10 CFR 50.46(b)(5).

Small Break Loss-of-Coolant Analyses

In their March 11, 1994, submittal, the licensee provided the results of a limited spectrum of SBLOCA analyses that were performed to account for the VCSNS plant design with the replacement steam generators. The analyses were performed using the Westinghouse SBLOCA Evaluation Model with NOTRUMP (WCAP-10054-P-A, August 1985), which has been approved by the NRC for licensing applications and is applicable to the Summer Station.

Sensitivity Studies and Spectrum Analysis

The licensee has referenced previous studies to support its conclusion that the limiting location of a small break continues to be a cold leg rupture. The analyses assume the reactor core is mixed, consisting of Westinghouse VANTAGE+ (ZIRLO) fuel, with Westinghouse VANTAGE 5 fuel. A special mixed core penalty was not assessed in the analyses because of the thermal/hydraulic similarity of VANTAGE 5 and VANTAGE+ fuels. Also a penalty was not assessed due to the presence of IFBA rods because of their geometric likeness to non-IFBA fuel rods. The analyses take credit for performance of HPI pumps that are capable of delivering at least a 321 gpm injection line flow rate, excluding the flow from the pump demonstrated to have the highest flow. The licensee provided the following sensitivity/spectrum analysis cases to identify and quantify the worst case:

1. 1.5-inch cold leg

2. 2-inch cold leg

3. 3-inch cold leg

Results of Licensing Basis SBLOCA Analysis

The 2-inch case above was identified as the worst SBLOCA case. In addition to the assumptions identified above, this case also assumed 102 percent of a core power level of 2900 MWt, a thermal design flow of 277,800 gpm, a vessel average temperature range of 572°F to 587.4°F, a hot channel enthalpy rise factor ($F_{\Delta H}$) of 1.62, a hot assembly average power (P_{HA}) of 1.443, a total core peaking factor (F_Q) of 2.45, and 10 percent uniform steam generator tube plugging. The calculated peak cladding temperature is 1860°F, the calculated maximum local metal/water reaction is 4.12 percent, and the calculated core-wide metal/water reaction is less than 1 percent. These results are within the criteria specified in 10 CFR 50.46(b) (1 through 3) of 2200°F, 17 percent, and 1 percent, respectively. The results assure that the core will remain amenable to cooling as required by 10 CFR 50.46(b)(4). The Summer Station ECCS design, as approved, assures continued conformance with the long-term cooling requirement of 10 CFR 50.46(b)(5). The results of the analyses of the limiting 2-inch SBLOCA are bounded by the results for the limiting LBLOCA.

LOCA Analysis Conclusions

The Summer Station LOCA analyses provided by the licensee in support of the steam generator replacement effort were performed with NRC-approved evaluation models and identify a DECLG cold leg break with a discharge coefficient of 0.4, with minimum safety injection and IFBA fuel as the limiting LOCA event. The results of the analysis of this event demonstrate conformance with the criteria specified in 10 CFR 50.46(b) and, therefore, the analyses are acceptable.

Maximum Centrifugal Charging Pump Flow Technical Specification Change

The licensee requested that TS 4.5.2.h.1.b, which governs the maximum allowed flow for the SI/Charging pumps, be changed to raise the maximum allowable flow for each pump from 680 gpm to 688 gpm. This TS is implemented by onsite pump surveillance testing to demonstrate that the pumps can pump at least the specified flow rate without being damaged by runout. The TS is provided as a surveillance requirement for the high pressure injection ECCS subsystem, and because the Summer Station LBLOCA (where ECCS pumps are most likely to experience runout) analyses take credit for HPI performance. The increase in the specified flow rate was proposed to increase the system's operating margin by providing a larger difference between minimum and maximum flow limits. The staff finds the proposed flow limit acceptable because it is consistent with the assumptions of the LOCA analyses which have been reviewed and found acceptable.

The staff has concluded that the proposed changes to Technical Specifications Figure 2.1-1, Table 2.2-1, Figure 3.1-1, 3.2.3, 4.2.3.5, Table 3.2-1, Table 3.3-1, Table 3.3-2, Table 4.3-1, Table 3.3-4, and 5.4.2 are acceptable.

2.4 Containment Systems Considerations

The licensee has performed containment integrity analyses to support the replacement of Westinghouse Model D3 with Delta 75 steam generators due to differences in flow and heat transfer areas. The analyses have been performed to ensure that the maximum pressure inside the containment will remain below the containment building design pressure of 57 psig if a design bases LOCA or main steam line break (MSLB) inside containment should occur during plant operation. The analyses also established the pressure and temperature conditions for environmental qualification and operation of safety-related equipment. The peak pressure is also used as a basis for the containment leak rate test pressure to ensure that dose limits will not be exceeded in the event of a release of radioactive material to containment in accordance with 10 CFR Part 50, Appendix J, and the TS. The analyses utilized the Engineered Safeguards Design Rating of 2900 MWt core power. This conservatively bounds the current licensed core power of 2775 MWt and minimizes future reanalysis effort for a potential stretch power application.

Main Steamline Break Containment Integrity Analysis

The licensee has performed analyses to determine the reactor building (RB) pressure and temperature response during postulated steamline breaks (SLBs) inside containment for a wide range of power levels and break sizes with the Delta 75 replacement steam generators (RSGs) and associated revised operating conditions. The licensee has indicated that reactor building initial conditions and assumptions used in the SLB analyses are consistent with those assumed in the current design basis except for the heat removal rate of the reactor building cooling units (RBCU) which is reduced by 40 percent below current assumptions to allow for future degradation in those units. The analyses were performed for initial power levels of 102 percent, 75 percent, 50 percent, 25 percent, and 0 percent, and a spectrum of break sizes similar to that in the current FSAR. The SLB mass and energy release and the pressure and temperature analyses have included the effects of various single failures including: failure of a main steam isolation valve; failure of a feedwater isolation valve; failure of electrical channel A, resulting in the loss of one diesel generator coincident with failure to isolate emergency feedwater flow to the faulted steam generator; and failure of one train of the safety injection system. The SLB mass and energy releases were calculated using the LOFTRAN computer code and RB temperature and pressure were calculated using the CONTEMPT-LT26 computer code. LOFTRAN and CONTEMPT-LT22 were used in the original design basis analyses. The use of the updated CONTEMPT-LT26 code has been approved for other plants, and the staff has found the use of this code to be acceptable.

Both RB pressure and temperature will increase during a postulated SLB with the Delta 75 steam generators. With the Model D3 steam generators, the calculated peak RB pressure and temperature following a SLB are calculated to be 45.96 psig and 321.5°F, respectively. With the Delta 75 steam generators,

the calculated peak RB pressure increases to 53 psig, and the peak temperature is calculated to reach 372.7°F. The peak temperature increases because there is no liquid entrainment in the steam for the worst case break. The superheated conditions within the RB are of short duration, during the first 100 seconds of the transient. Following spray actuation, the RB remains saturated in the long-term and stays below the RB design temperature of 283°F. Safety-related equipment inside the containment will be qualified to operate in an accident environment with pressure and temperature equal to or higher than 53.5 psig and 379.2°F, respectively.

The staff has determined that the licensee's analysis of containment performance during a postulated SLB is adequate to support steam generator replacement.

LOCA Containment Integrity Analysis

The licensee has performed analyses to determine the reactor building pressure and temperature response during postulated LOCAs following steam generator replacement. The RB initial conditions used in the analyses are consistent with those assumed in the current licensing basis analysis except that RBCU heat removal capacity is reduced by more than 50 percent to account for possible future heat transfer degradation of these units.

The LOCA analyses are performed for the double ended hot leg (DEHL) guillotine break and the double ended pump suction (DEPS) break with minimum and maximum safety injection, minimum RB spray, and minimum and maximum RBCU performance. The mass and energy releases in the containment are calculated using Westinghouse topical report WCAP-10325-A. The containment pressure and temperature response is calculated using the CONTEMPT-LT26 computer code. Westinghouse topical report WCAP-8312A and CONTEMPT-LT22 were used for the original design bases analyses. The updated WCAP-10325 and CONTEMPT-LT26 computer codes have been used for other plants and the staff has found the use of these codes acceptable.

Following steam generator replacement, the peak RB pressure and temperature will occur following a postulated DEHL break. In the updated analyses, the peak RB pressure will be 45.1 psig, and the peak RB temperature will be 267.4°F. These values are below the design pressure of 57 psig and design temperature of 283°F.

The staff has determined that the licensee's analysis of containment performance during a postulated SLB is adequate to support steam generator replacement.

Containment Subcompartment Analysis

The licensee has evaluated the effect of short-term LOCA mass and energy releases on the containment subcompartment analysis following steam generator replacement. The subcompartments (steam generator compartments, pressurizer compartment, and reactor cavity) were analyzed for the largest breaks possible in each compartment; pressurizer compartment for spray line and surge line

breaks; steam generator compartments for double-ended hot leg and cold leg breaks, and reactor cavity for 150 in^2 cold leg break.

The licensee indicated that the current LOCA pressures, forces, and moments used in the original steam generator compartment and reactor cavity design analysis remain bounding for the replacement steam generators. The use of the previously approved leak-before-break methodology eliminates the dynamic effects of postulated primary loop ruptures from the design bases. The licensee indicated that based on the change in peak critical mass flux and temperature, the impact on the pressurizer compartment can be conservatively bounded by increasing the surge and spray line mass release by factors of 15 percent and 10 percent, respectively. The licensee calculated that the differential pressures resulting from potential increases in surge line and spray line mass and energy releases are shown to increase in the pressurizer compartment and decrease in the surge tank compartment; however, large margins continue to be maintained between the calculated and design pressures.

Based on the results of the LOCA calculations and evaluations described above, the staff finds the proposed change acceptable, because it will affect neither the subcompartments nor equipment located in the subcompartments.

Containment Leakage

The licensee has proposed to increase the peak containment pressure (Pa) for leak testing from 47.1 psig to 53.5 psig or (Pt) from 23.6 psig to 26.8 psig based on reanalyzed peak pressure expected from a SLB event. Since Appendix J to 10 CFR Part 50 requires the licensee to perform leak testing at the peak accident pressure, and the TS require the containment leakage limit, which remains the same, to be satisfied, the staff finds the higher containment pressure with the present leakage limit to be acceptable.

2.5 Radiological Considerations

The licensee performed various reanalyses of the Summer FSAR Chapter 15 accidents. Such reanalyses were required in order to incorporate (1) the transition to VANTAGE+ fuel, (2) the installation of the RSGs, and (3) the revised design power capability parameters. To support these reanalyses the licensee recalculated reactor core and reactor coolant iodine and noble gas fission product activities. These activities were then utilized in the calculation of offsite doses for the following postulated accidents:

1. Loss of Offsite Power
2. Waste Gas Decay Tank Rupture
3. Break in CVCS Line
4. Large Break LOCA
5. Main Steam Line Break
6. Steam Generator Tube Rupture
7. Locked Rotor

Reanalyses were also performed of the offsite consequences of the fuel handling and rod ejection accidents. In the licensee's analyses to support the RSGs, the licensee incorporated the Engineered Safeguards Design Rating

"stretch" power rating of 2,900 MWt core power. The licensee stated that this power rating was utilized to conservatively bound the current licensed core power of 2,775 MWt and to minimize future required reanalysis for a potential stretch power application. However, the licensee's submittal was quite specific in stating that approval for operation at stretch power was not being sought at this time. A comparison of the VANTAGE+ core, coolant activities, and fuel handling accident source terms with those of a VANTAGE 5 core and a generic 2,900 MWt core was provided. The following sections provide the staff's assessment of the potential consequences of postulated accidents based upon the switch to Vantage+ fuel and the RSG. The licensee's assessment of the switch to Vantage+ fuel on the core source term, the reactor coolant activity levels, and the fuel handling accident source term are discussed in the following sections along with the staff's assessment.

Core Source Term

The licensee stated that an increase in the maximum fuel burnup limit would occur with the transition from VANTAGE 5 fuel to VANTAGE+ fuel. For VANTAGE+ fuel, the peak fuel pin burnup is 75,000 MWD/MTU, an increase of 15,000 MWD/MTU over the current peak fuel pin burnup. Utilization of VANTAGE+ fuel would result in a slight decrease in short-lived iodine isotopes and in short-lived noble gases, except ^{133}Xe and ^{135}Xe. The inventory of ^{85}Kr would increase significantly with the extended burnup due to the increased fuel cycle length and ^{235}U enrichment. In general, core inventory activity for all nuclides increases in the transition from VANTAGE 5 fuel to VANTAGE+ fuel. However, the increases are due primarily to the increased core power.

Reactor Coolant Activity

In the calculation of rector coolant fission product activity, the licensee assumed the equivalent of 1% of the fuel rods with small cladding defects. One parameter which only affects coolant activity is letdown flow rate. For the generic plant, letdown flow was assumed to be 75 gpm while 60 gpm was assumed for VANTAGE 5 and VANTAGE+ fuel. The decrease in letdown flow rate results in a decrease in the non-radioactive decay removal terms. Thus, for a given burnup and fuel type, somewhat higher coolant activities result. This is particularly true for the longer-lived isotopes.

Fuel Handling Accident Source Term

The fuel handling accident source term is a fraction of the core source term and represents the gap activity contained in one or more fuel assemblies which has been decayed for 100 hours. In addition to the specific parameters of the fuel handling accident, all of the phenomena affecting core activity also affect the fuel handling accident source term. The VANTAGE+ activity is substantially greater than the VANTAGE 5 activity primarily due to the increased power level and the increased number of damaged fuel rods assumed. The licensee assumed the gap activity, with the exception of the VANTAGE+ ^{131}I value, to be that assumed in Regulatory Guide 1.25. For ^{131}I the gap fraction was 0.12.

Loss of Offsite Power

The licensee indicated that a loss of offsite power would not result in the release of radioactivity unless there was a primary to secondary leak in the steam generators. The analysis assumed a reactor coolant concentration based upon 1% failed fuel and a 1 gpm primary to secondary leak rate. Other pertinent assumptions are presented in Table 3.7.1-1. The staff assessed the potential consequences of a loss of offsite power with the assumptions in this Table. The thyroid and whole body doses are presented in Tables 3.7.4-1 and 3.7.4-2, respectively. The doses were found acceptable.

Waste Gas Decay Tank Rupture

The licensee reevaluated the consequences of a waste gas decay tank rupture. The licensee's submittal stated that the analysis was performed not because of the RSG or due to changes in the design power capability, but rather to reflect TS limits on decay tank radioactivity. The licensee assumed the release of 160,000 Ci of ^{133}Xe. Gamma and beta doses were calculated at the Exclusion Area Boundary (EAB) and the Low Population Zone (LPZ). The staff independently assessed the potential consequences of the release of the contents of a waste gas decay tank. The acceptance criterion for the release of the contents of a waste gas decay tank is 0.5 rem total body. Based upon this criterion, the staff determined that the allowable waste gas tank inventory would be approximately 131,000 Ci of ^{133}Xe. While this particular issue is not associated with the replacement of the D3 steam generators, the licensee should reevaluate the determination of the allowable TS quantity of ^{133}Xe in the waste gas decay tank.

Break in CVCS Line

The licensee evaluated the potential release of activity from pipes associated with the reactor coolant system. They considered instrument lines which are connected to the reactor coolant system and penetrate containment. None existed. Certain grab sample line were found which did penetrate containment, but these lines were equipped with normally closed isolation valves both inside and outside containment. In addition, these lines had been designed in accordance with GDC 55. A postulated break of the chemical volume control system (CVCS) letdown line was considered. The analysis assumed radioactivity in the reactor coolant based upon 1% failed fuel and that an iodine spike had occurred as a result of reactor shutdown or depressurization of the primary system. The staff's assumptions associated with its analysis of this accident are presented in Table 3.7.3.3-1. The thyroid and whole body doses are presented in Tables 3.7.4-1 and 3.7.4-2, respectively. The doses were found acceptable.

Large Break LOCA

The licensee calculated the potential consequences of a postulated LOCA to the control room operators and to individuals located at the EAB and LPZ. The sources of releases in the event of a LOCA include containment leakage and emergency core cooling system (ECCS) recirculation loop leakage. Containment sources were assumed to be reduced by the effects of engineered safety feature

equipment such as sprays and HEPA filters. Recirculation loop leakage was assumed to be released with no credit for holdup or filtration by the Auxiliary Building HEPA/charcoal filter system. Additional details on the assumptions for this evaluation are presented in Table 3.7.3.4-1. The staff assessed the potential consequences of a LOCA based upon the assumptions in this Table. The thyroid and whole body doses are presented in Tables 3.7.4-1 and 3.7.4-2, respectively. The doses were found to be acceptable.

Main Steam Line Break

The licensee reevaluated the consequences of a postulated main steam line break outside containment. Two analyses were performed. In both cases, a pre-existing, 1 gpm primary to secondary steam generator tube leak was assumed. For one analysis, it was assumed that a pre-existing iodine spike had occurred prior to the steam line break. Reactor coolant iodine specific activities were assumed to be at the TS Figure 3.4-1 full power limit of 60 μCi/gm of dose equivalent ^{131}I. Noble gas activity levels were assumed to be 60 times the 1% failed fuel values. The secondary coolant iodine specific activity was based upon secondary coolant specific activity equilibrium being reached with the reactor coolant iodine specific activity at 60 μCi/gm, a primary to secondary leak rate of 1 gpm, and a SG blowdown rate of 30 gpm total for 3 SGs.

The second analysis assumed the steam line break initiated a concurrent iodine spike. The rector coolant was assumed to be at the TS normal operation limit of 1 μCi/gm dose equivalent ^{131}I and at the 1% failed fuel specific activity for noble gases. The secondary system activity was assumed to be at the TS normal operation limit of 0.1 μCi/gm dose equivalent ^{131}I. Concurrent with the main steam line break, an iodine spike was assumed to occur which releases iodine from the fuel gap to the reactor coolant at a rate in Ci/min which is 500 times the normal iodine release rate. The main steam line break event was assumed to result in no failed fuel and no additional release of fuel gap inventory to the reactor coolant.

For both analyses it was assumed that the 1 gpm primary to secondary tube leak occurred in the faulted SG until it was isolated. After isolation, the 1 gpm leak rate was assumed to be distributed to the two intact SGs. Any noble gases released to the secondary side were assumed to be released continuously from the SGs and the secondary system. It was also assumed that offsite power was lost and the main condenser was unavailable for steam dump. After 8 hours, no further steam release or activity release was assumed to occur due to the steam line break.

Table 3.7.3.6-1 contains details on the staff's assumptions. The staff assessment resulted in the doses presented in Tables 3.7.4-1 and 3.7.4-2. The staff's assessment also included an assessment of the control room operator doses as a result of a LOCA.

Steam Generator Tube Rupture

The licensee reevaluated the consequences of a postulated SG tube rupture (SGTR). Two analyses were performed. In both cases it was assumed that a 1

gpm primary to secondary steam generator tube leak existed prior to and following the SGTR. In the first case it was assumed that a pre-existing iodine spike had occurred prior to the steam line break. Reactor coolant iodine specific activities were assumed to be at the TS Figure 3.4-1 full power limit of 60 μCi/gm of dose equivalent ^{131}I. Noble gas activity levels were assumed to be 60 times the 1% failed fuel values. The secondary coolant iodine specific activity was based upon secondary coolant specific activity equilibrium being reached with the reactor coolant iodine specific activity at 60 μCi/gm, a primary to secondary leak rate of 1 gpm, and a SG blowdown rate of 30 gpm total for 3 SGs.

The second case analyzed assumed the SGTR initiated a concurrent iodine spike. The rector coolant was assumed to be at the TS normal operation limit of 1 μCi/gm dose equivalent ^{131}I and at the 1% failed fuel specific activity for noble gases. The secondary system activity was assumed to be at the TS normal operation limit of 0.1 μCi/gm dose equivalent ^{131}I. Concurrent with the SGTR, an iodine spike was assumed to occur which releases iodine from the fuel gap to the reactor coolant at a rate in Ci/min which is 500 times the normal iodine release rate. The SGTR was assumed to result in no failed fuel and no additional release of fuel gap inventory to the reactor coolant.

For both analyses it was assumed that the 1 gpm primary to secondary tube leak occurred in the intact SGs for the duration of the accident. Any noble gases released to the secondary side were assumed to be released continuously from the SGs and the secondary system. Additionally, it was assumed that offsite power was lost and the main condenser was unavailable for steam dump. After 8 hours no further steam release or activity release was assumed to occur due to the SGTR.

Table 3.7.3.7-1 presents the assumptions utilized by the staff in their assessment. The potential consequences of a SGTR accident are presented in Tables 3.7.4-1 and 3.7.4-2. The doses were found to be acceptable.

Locked Rotor

The licensee assumed a postulated reactor coolant pump locked rotor event and subsequent leakage of steam from the secondary system due to the leakage of reactor coolant to the secondary system. Leakage from the primary side to the secondary side was assumed to exist prior to the accident. For the initial conditions, the reactor coolant concentrations were based upon 1% failed fuel, and the locked rotor event induced 15% fuel failure.

Table 3.7.3.7-1 presents the assumptions utilized by the staff in their assessment of the consequences of a locked rotor accident. It should be noted that the licensee's analysis had only 10% of the ^{131}I activity in the gap when the value should have been 12% based upon the extended burnup and additional enrichment associated with the Vantage+ fuel. The staff's assessment of the potential consequences of a locked rotor accident are presented in Tables 3.7.4-1 and 3.7.4-2. The doses were found to be acceptable.

Fuel Handling Accident

The licensee considered two accident scenarios for fuel handling accidents. The first scenario assumed a refueling accident occurred inside the containment. In this scenario it was assumed that spent fuel assembly was dropped onto the core which resulted in damage to fuel assemblies. Following the drop, the activity released to the reactor building atmosphere was assumed to be released instantaneously to the environment through the reactor building purge system. No credit was taken for a reduction in the amount of activity released as a result of either filtration or decay due to holdup in the reactor building.

The second scenario assumed a refueling accident occurred outside containment. The dropping of a spent fuel assembly onto the spent fuel pool was assumed to result in damage to fuel assemblies and the release of the volatile gaseous fission products to the spent fuel pool with subsequent release to the fuel handling building and then to the environment through the fuel handling building charcoal exhaust system. The licensee's analysis assumed no credit for the mixing of the activity in the fuel building, nor credit for decay due to holdup in the fuel building nor credit for decay due to transit time after release to the environment. All releases from the fuel building were assumed to be removed at an efficiency of 95% for all forms of iodine.

Table 3.7.3.8-1 contains details of the assumptions utilized by the staff in its assessment of the potential consequences of a fuel handling accident. The offsite doses are presented in Tables 3.7.4-1 and 3.7.4-2. The thyroid dose for the accident inside containment (designated as the reactor building at Summer) is greater than the design criterion of 75 rem included in SRP 15.7.4. However, the mitigation of the consequences of a fuel handling accident at Summer is based upon safety grade radiological monitors isolating the containment in the event of a fuel handling accident. If it is assumed that the containment is being purged at a rate of 20,000 cfm and the containment is isolated approximately 41 seconds after the accident, the thyroid dose is less than the SRP value of 75 rem even when it is assumed that the release mixes with 20% of the reactor building volume.

Rod Ejection

The licensee performed an analysis of a postulated rod ejection accident. It was assumed that the reactor was operating with equilibrium activity levels in the primary and secondary systems based upon 1% failed fuel and a primary to secondary leak rate of 1 gpm. Following the rod ejection accident two potential activity release paths contribute to the offsite consequences. The first pathway is via containment leakage of activity released to the reactor building from reactor coolant. The second pathway is the release of contaminated steam from the secondary side through the relief valves since the assumption is made that offsite power is lost. The licensee's analysis assumed that the rod ejection resulted in an additional fuel failure of 10%.

Table 3.7.3.9-1 presents the assumptions utilized by the staff in their assessment. The potential consequences are presented in Tables 3.7.4-1 and 3.7.4-2. It should be noted that the licensee's analysis had only 10% of the

^{131}I activity in the gap when the value should have been 12% based upon the extended burnup and additional enrichment associated with the Vantage+ fuel. The latter value was utilized by the staff in its assessment. The doses were found acceptable.

Conclusions

The staff has assessed those accidents for which the change to the Delta 75 replacement steam generators have an impact upon the offsite and control room operator doses. As a result of that assessment, the staff has concluded that, for those accidents which are impacted by the change to the Delta 75 steam generators, the doses would not exceed the dose guidelines presently contained in the Standard Review Plans, 10 CFR Part 100 or GDC 19 of 10 CFR Part 50, Appendix A for either offsite locations or control room operators. Therefore, the staff finds the proposed replacement of the D3 steam generators with the Delta 75 steam generators acceptable from a radiological standpoint.

Table 3.7.1-1 Licensee's Assumptions for Loss of Offsite Power Event

Mass of steam released from 3 steam generators (lbs)

447,900	(0-2 hours)
868,300	(2-8 hours)

Feedwater flow to the 3 steam generators (lbs)

375,500	(0-2 hours)
841,800	(2-8 hours)

Steam generator blowdown rate (gpm)	10
Reactor Coolant concentrations	Based upon 1% failed fuel
Iodine Partition Factor in the steam generators	0.01

Table 3.7.3.3-1 Assumptions for CVCS Letdown Line Rupture

Fuel Defects	1%
Break Flow Rate (gpm)	100
Break Flow Isolation Time (min)	30
Reactor Coolant concentrations	Based upon 1% failed fuel
Iodine Partition Factor	
Iodine	0.1
Noble Gases	1.

Table 3.7.3.4-1 Assumptions for LOCA Analysis

Core Thermal Power (MWt)	2958
Activity Released to the Reactor Building	
Airborne (fraction of core)	
Iodine	0.5
Noble Gases	1.0
Iodine Plateout Factor	0.5
Iodine Species (fraction)	
Elemental	0.91
Particulate	0.05
Organic	0.04
Activity Released to Sump (fraction)	
Iodine	0.5
Noble Gases	0.0
Reactor Building	
Free Volume (ft^3)	1.84E6
Leakage Rate (%/day)	
0-24 hours	0.2
> 24 hours	0.1
Sump Liquid Volume (ft^3)	5.83E4
Reactor Building Cooling Unit	
Flow Rate (cfm)	5.42E4
Recirculation Efficiency (%)	
Elemental Iodine	0
Organic Iodine	0
Particulate Iodine	90

Table 3.7.3.4-1 Assumptions for LOCA Analysis (continued)

Reactor Building Spray System	
Actuation Time (sec)	52
Spray Removal Constants (/hr)	
Elemental	10
Particulate	0.207
Fraction of Reactor Building Unsprayed	0.25
Recirculation Loop	
Leakage Rate (cc/hr)	5860
Minimum Time to Recirculation (sec)	2335
Passive Component Failure Leak Rate (gpm) for 30 minutes @24 hours post-LOCA	50
Control Room	
Free Volume (ft^3)	2.26E5
Filtered Recirculation Flow (cfm)	1.91E4
Recirculation Efficiency (%) for all forms of Iodine	95
Makeup Air Filtration Rate (cfm)	1000
Unfiltered Air Infiltration Rate (cfm)	10
Occupancy Factors	
0-1 day	1.0
1-4 days	0.6
4-30 days	0.4

Table 3.7.3.4-1 Assumptions for LOCA Analysis (continued)

Atmospheric Dispersion Factors (sec/m^3)	
EAB	4.08E-4
LPZ	
0-8 hours	4.1E-5
8-24 hours	2.6E-5
1-4 days	1.0E-5
4-30 days	2.6E-6
Control Room	
0-8 hours	2.6E-3
8-24 hours	1.7E-3
1-4 days	5.8E-4
4- 30 days	1.1E-4
Breathing Rates (m^3/sec)	
Offsite	
0-8 hours	3.47E-4
8-24 hours	1.75E-4
1-30 days	2.32E-4
Control Room	3.47E-4

Table 3.7.3.6-1 Assumptions for Main Steam Line Break Accident

Iodine Partition Factor	
Faulted SG	1.0
Intact SGs	0.01
Steam and H_2O from Faulted SG	
0-30 minutes	
Pre-existing Spike Case (lbs)	1.13E5
Concurrent Spike (lbs)	4.06E5
0.5-8 hours (lbs)	0
Steam Release from Intact SGs (lbs)	
0-2 hours	3.44E5
2-8 hours	7.34E5
Feedwater Flow to Intact SGs (lbs)	
0-2 hours	4.46E5
2-8 hours	7.22E5

Table 3.7.3.7-1 Assumptions for SGTR Accident

Iodine Partition Factor	0.1
Steam Release from Defective SG	
0-0.5 hours(lbs)	5.68E4
0.5-8 hours (lbs)	0
Steam Release from Intact SGs (lbs)	
0-2 hours	3.81E5
2-8 hours	9.25E5
Feedwater Flow to Intact SGs (lbs)	
0-2 hours	3.71E5
2-8 hours	9.86E5
Reactor Coolant Released to Faulted SG (lbs)	9.29E4
Primary to Secondary Leak Rate (gpm)	1
Time to Isolate Faulted SG (min)	30

Table 3.7.3.7-1 Assumptions for Locked Rotor Accident

Gap Fraction:	
^{131}I	0.12
^{85}Kr	0.30
All others	0.10
Failed Fuel Rods (%)	15
Primary to Secondary Leak Rate (gpm)	1
Iodine Partition Factor in SG	0.1
Steam Released from 3 SGs (lbs)	
0-2 hours	4.48E5
2-8 hours	8.68E5
Feedwater Delivered to 3 SGs (lbs)	
0-2 hours	3.76E5
2-8 hours	8.42E5

Table 3.7.8-1 Assumptions for Fuel Handling Accidents

Core Power (MWt)	2958
Number of Assemblies	157
Highest Power Discharged Assembly	
Axial Peak to Average Ratio	1.7
Radial Peak to Average Ratio	1.7
Occurrence of Accident (hours after shutdown)	100
Damaged fuel rods	314
Activity released from the gap	
Noble gases except ^{85}Kr	0.10
^{85}Kr	0.30
Iodine except ^{131}I	0.10
^{131}I	0.12
Iodine Gap Inventory	
organic(%)	0.25
inorganic(%)	99.75
Pool DF	
organic(%)	1
inorganic(%)	133
Purge Isolation Time (seconds)	41.2
Fuel Handling Building Adsorber Efficiency	
organic (%)	95
inorganic (%)	95

Table 3.7.3.9-1 Assumptions for Rod Ejection Accident

Core Thermal Power (MWt)	2958
Fuel Defects (%)	1
Primary to Secondary Leak Rate (gpm)	1
Failed Fuel (% of core fuel)	10
Activity release to reactor coolant from failed fuel and available for release (% of gap inventory)	10
Melted Fuel (% of core)	
Case 1	0
Case 2	0.25
Activity released to reactor coolant from melted fuel and available for release (% of core inventory)	
Case 1	0
Case 2	0.25 for noble gases 0.125 for iodine
Iodine Partition Factor in the SGs before and after the accident	0.01
Reactor Building	
Volume (ft^3)	1.84E6
Leak Rate (%/day)	0.2 for t = 0-1 day 0.1 for t > 1 day
Iodine Form in Containment (fraction)	
Particulate	0.05
Organic	0.04
Elemental	0.91
Steam Dump from Relief Valves (lbs)	3.3E4
Duration of Steam Dump from Relief Valves (sec)	150
Time between Accident and Equalization of Primary to Secondary System Pressure (sec)	175

Table 3.7.4-1 Thyroid Doses from Postulated Accidents (Rem)

	Accident	EAB	LPZ
1.	Loss of Offsite Power	<1	<1
2.	Waste Gas Decay Tank Rupture	N/A	N/A
3.	Break in CVCS Line	1.2	<1
4.	Large Break LOCA		
	Containment	134	56
	ECCS Leakage	4	42
	Control Room	25	
5.	Main Steam Line Break		
	Coincident Spike	<1	<1
	Pre-existing Spike	3.8	<1
6.	Steam Generator Tube Rupture		
	Coincident Spike	8.8	<1
	Pre-existing Spike	9.2	<1
7.	Locked Rotor	77	64
8.	Fuel Handling Accident		
	Inside Containment	145	15
	Fuel Handling Bldg.	7.2	0.7
9.	Rod Ejection	84	40

N/A - Not Applicable

Table 3.7.4-2 Whole Body Doses from Postulated Accidents (Rem)

	Accident	EAB	LPZ
1.	Loss of Offsite Power	<1	<1
2.	Waste Gas Decay Tank Rupture	0.6	<0.1
3.	Break in CVCS Line	2.8	<1
4.	Large Break LOCA		
	Containment	4.0	1
	ECCS Leakage	<1	<1
	Control Room	3.7	
5.	Main Steam Line Break		
	Coincident Spike	<1	<1
	Pre-existing Spike	<1	<1
6.	Steam Generator Tube Rupture		
	Coincident Spike	<1	<1
	Pre-existing Spike	<1	<1
7.	Locked Rotor	<1	<1
8.	Fuel Handling Accident		
	Inside Containment	<1	<1
	Fuel Handling Bldg.	<1	<1
9.	Rod Ejection	<1	<1

3.0 STATE CONSULTATION

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

4.0 ENVIRONMENTAL CONSIDERATION

The amendment changes a requirement with respect to installation or use of a facility component located within the restricted area as defined in 10 CFR Part 20 and changes the Surveillance Requirements. The NRC staff has determined that the amendment involves no significant increase in the amounts, and no significant change in the types, of any effluents that may be released offsite, and that there is no significant increase in individual or cumulative occupational radiation exposure. The Commission has previously issued a proposed finding that the amendment involves no significant hazards consideration, and there has been no public comment on such finding (59 FR 7698). Accordingly, the amendment meets the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Pursuant to 10 CFR 51.22(b) no environmental impact statement or environmental assessment need be prepared in connection with the issuance of the amendment.

5.0 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 amendment will not be inimical to the common defense and security or to the health and safety of the public.

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