TABLE 2.2-1

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TOTAL ALLOWANCE (TA)	Z	SENSOR ERROR (S)	TRIP SETPOINT	ALLOWABLE VALUE
1. Manual Reactor Trip	N.A.	N.A.	N.A.	N.A.	N.A.
2. Power Range, Neutron Flux					
a. High Setpoint	7.5	4.56	1.25	≤109% of RTP*	≤111.7% of RTP*
b. Low Setpoint	8.3	4.56	1.25	≤25% of RTP*	≤27.7% 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. Power Range, Neutron Flux, High Negative 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
5. Intermediate Range, Neutron Flux	17.0	8.41	0	≤25% of RTP*	≤31.5% of RTP*
6. Source Range, Neutron Flux	17.0	10.01	0	≤10^5 cps	≤1.4 x 10^5 cps
7. Overtemperature N-16					
a. Unit 1	5.8	3.65	1.2+0.8(1)	See Note 1	See Note 2
b. Unit 2	10.0	6.75	1.0+1.38+0.96(2)	See Note 1	See Note 2
8. Overpower N-16					
a. Unit 1	4.0	1.93	0	≤112% of RTP*	≤115.1% of RTP*
b. Unit 2	4.0	2.05	1.0+0.05(3)	≤112% of RTP*	≤114.5% of RTP*
9. Pressurizer Pressure-Low					
a. Unit 1	4.4	0.71	2.0	≥1880 psig	≥1863.6 psig
b. Unit 2	4.4	1.12	2.0	≥1880 psig	≥1863.6 psig
10. Pressurizer Pressure-High					
a. Unit 1	7.5	5.01	1.0	≤2385 psig	≤2400.8 psig
b. Unit 2	7.5	1.12	2.0	≤2385 psig	≤2401.4 psig

*RTP = RATED THERMAL POWER

(1) 1.2% span for delta-T (RTDs) and 0.8% for pressurizer pressure.

(2) 1.0% span for N-16 power monitor; 1.38% for T_{cold} RTDs and 0.96% for pressurizer pressure sensors.

(3) 1.0% span for N-16 power monitor and 0.05% for T_{cold} RTDs.

TABLE 2.2-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TOTAL ALLOWANCE (TA)	Z	SENSOR ERROR (S)	TRIP SETPOINT	ALLOWABLE VALUE
11. Pressurizer Water Level-High					
a. Unit 1	8.0	2.18	2.0	<92% of instrument span	<93.9% of instrument span
b. Unit 2	8.0	2.35	2.0	≤92% of instrument span	≤93.9% of instrument span
12. Reactor Coolant Flow-Low					
a. Unit 1	2.5	1.18	0.6	>90% of loop design flow**	>88.6% of loop design flow**
b. Unit 2	2.5	1.25	0.87	≥90% of loop minimum measured flow***	≥88.8% of loop minimum measured flow***
13. Steam Generator Water Level - Low-Low					
a. Unit 1	25.0	22.08	2.0	>25.0% of narrow range instrument span	>23.1% of narrow range instrument span
b. Unit 2	35.4	22.2	2.0	≥35.4% of narrow range instrument span	≥33.4% of narrow range instrument span
14. Undervoltage - Reactor Coolant Pumps					
a. Unit 1	7.7	0	0	>4830 volts-each bus	>4753 volts-each bus
b. Unit 2	7.7	1.2	0	≥4830 volts-each bus	≥4753 volts-each bus
15. Underfrequency - Reactor Coolant Pumps					
a. Unit 1	4.4	0	0	≥57.2 Hz	≥57.1 Hz
b. Unit 2	4.4	0	0	≥57.2 Hz	≥57.06 Hz
16. Turbine Trip					
a. Low Trip System Pressure	N.A.	N.A.	N.A.	>59 psig	>46.6 psig
b. Turbine Stop Valve Closure	N.A.	N.A.	N.A.	>1% open	>1% open
17. Safety Injection Input from ESF	N.A.	N.A.	N.A.	N.A.	N.A.

**Loop design flow = 95,700 gpm.

***Loop minimum measured flow = 98,500 gpm

TABLE 2.2-1 (Continued)

TABLE NOTATIONS

NOTE 1: Overtemperature N-16

$$N = K_1 - K_2 \left[\frac{1+\tau_1 S}{1+\tau_2 S} T_c - T_c^{o} \right] + K_3 (P - P^1) - f_1 (\Delta q)$$

Where:

N	=	Measured N-16 Power by ion chambers,
T_c	=	Cold leg temperature, °F,
T_c^o	=	559.6°F for Unit 1, Reference T_c at RATED THERMAL POWER, 560.3°F for Unit 2
K_1	=	1.078 for Unit 1 1.150 for Unit 2
K_2	=	0.00948/°F for Unit 1 0.016856/°F for Unit 2
$\frac{1+\tau_1 S}{1+\tau_2 S}$	=	The function generated by the lead-lag controller for T_c dynamic compensation,
τ_1, τ_2	=	Time constants utilized in the lead-lag controller for T_c, $\tau_1 \geq 10$ s, and $\tau_2 \leq 3$ s,
K_3	=	0.000494/psig for Unit 1 0.000898/psig for Unit 2

TABLE 2.2-1 (Continued)

TABLE NOTATIONS (Continued)

NOTE 1: (Continued)

P = Pressurizer pressure, psig,

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

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

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

For Unit 1

(i) for $q_t - q_b$ between -35% and +10%, $f_1(\Delta q) = 0$, 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%, the N-16 Trip Setpoint shall be automatically reduced by 1.22% of its value at RATED THERMAL POWER, and

(iii) for each percent that the magnitude of $q_t - q_b$ exceeds +10%, the N-16 Trip Setpoint shall be automatically reduced by 1.40% of its value at RATED THERMAL POWER.

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NOTE 2: The channel's maximum Trip Setpoint shall not exceed its computed Trip Setpoint by more than 1.8% of span (for Unit 1) or 2.88% of span (for Unit 2).

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For Unit 2:

(i) for $q_t - q_b$ between -52% and +5.5%, $f_1(\Delta q) = 0$, 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 -52%, the N-16 Trip Setpoint shall be automatically reduced by 2.15% of its value at RATED THERMAL POWER, and

(iii) for each percent that the magnitude of $q_t - q_b$ exceeds +5.5%, the N-16 Trip Stepoint shall be automatically reduced by 2.17% of its value at RATED THERMAL POWER.

3/4.0 APPLICABILITY

LIMITING CONDITION FOR OPERATION

3.0.1 Compliance with the Limiting Conditions for Operation contained in the succeeding specifications is required during the OPERATIONAL MODES or other conditions specified therein; except that upon failure to meet the Limiting Conditions for Operation, the associated ACTION requirements shall be met.

3.0.2 Noncompliance with a specification shall exist when the requirements of the Limiting Condition for Operation and associated ACTION requirements are not met within the specified time intervals. If the Limiting Condition for Operation is restored prior to expiration of the specified time intervals, completion of the ACTION requirements is not required.

3.0.3 When a Limiting Condition for Operation is not met, except as provided in the associated ACTION requirements, within 1 hour action shall be initiated to place the unit in a MODE in which the specification does not apply by placing it, as applicable, in:

a. At least HOT STANDBY within the next 6 hours,

b. At least HOT SHUTDOWN within the following 6 hours, and

c. At least COLD SHUTDOWN within the subsequent 24 hours.

Where corrective measures are completed that permit operation under the ACTION requirements, the action may be taken in accordance with the specified time limits as measured from the time of failure to meet the Limiting Condition for Operation. Exceptions to these requirements are stated in the individual specifications.

This specification is not applicable in MODE 5 or 6.

3.0.4 Entry into an OPERATIONAL MODE or other specified condition shall not be made when the conditions for the Limiting Conditions for Operation are not met and the associated ACTION requires a shutdown if they are not met within a specified time interval. Entry into an OPERATIONAL MODE or specified condition may be made in accordance with ACTION requirements when conformance to them permits continued operation of the facility for an unlimited period of time. This provision shall not prevent passage through or to OPERATIONAL MODES as required to comply with ACTION requirements. Exceptions to these requirements are stated in the individual specifications.

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3.0.5 Limiting Conditions for Operation including the associated ACTION requirements shall apply to each unit individually unless otherwise indicated as follows:

a. Whenever the Limiting Conditions for Operation refers to systems or components which are shared by both units, the ACTION requirements will apply to both units simultaneously, unless specifically noted otherwise, and will be denoted in the ACTION section of the specification;

b. Whenever the Limiting Conditions for Operation applies to only one unit, this will be identified in the APPLICABILITY section of the specification; and

c. Whenever certain portions of a specification contain operating parameters, setpoints, etc., which are different for each unit, this will be identified in parentheses, footnotes or body of the requirement.

Therefore, if remedial measures are completed that would permit a return to POWER operation, a penalty is not incurred by having to reach a lower MODE of operation in less than the total time allowed.

The same principle applies with regard to the allowable outage time limits of the ACTION requirements, if compliance with the ACTION requirements for one specification results in entry into a MODE or condition of operation for another specification in which the requirements of the Limiting Condition for Operation are not met. If the new specification becomes applicable in less time than specified, the difference may be added to the allowable outage time limits of the second specification. However, the allowable outage time limits of ACTION requirements for a higher MODE of operation may not be used to extend the allowable outage time that is applicable when a Limiting Condition for Operation is not met in a lower MODE of operation.

The shutdown requirements of Specification 3.0.3 do not apply in MODES 5 and 6, because the ACTION requirements of individual specifications define the remedial measures to be taken.

Specification 3.0.4 establishes limitations on MODE changes when a Limiting Condition for Operation is not met. It precludes placing the facility in a higher MODE of operation when the requirements for a Limiting Condition for Operation are not met and continued noncompliance to these conditions would result in a shutdown to comply with the ACTION requirements if a change in MODES were permitted. The purpose of this specification is to ensure that facility operation is not initiated or that higher MODES of operation are not entered when corrective action is being taken to obtain compliance with a specification by restoring equipment to OPERABLE status or parameters to specified limits. Compliance with ACTION requirements that permit continued operation of the facility for an unlimited period of time provides an acceptable level of safety for continued operation without regard to the status of the plant before or after a MODE change. Therefore, in this case, entry into an OPERATIONAL MODE or other specified condition may be made in accordance with the provisions of the ACTION requirements. The provisions of this specification should not, however, be interpreted as endorsing the failure to exercise good practice in restoring systems or components to OPERABLE status before plant startup.

When a shutdown is required to comply with ACTION requirements, the provisions of Specification 3.0.4 do not apply because they would delay placing the facility in a lower MODE of operation.

Specifications 4.0.1 through 4.0.6 establish the general requirements applicable to Surveillance Requirements. These requirements are based on the Surveillance Requirements stated in the Code of Federal Regulations, 10 CFR 50.36(c)(3):

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<u>Specification 3.0.5</u> delineates the applicability of each specification to Unit 1 and 2 operation.

The valve identification numbers (tag numbers) contain a unit designator as the first character, i.e. 1CS-8455 would be a Unit 1 valve with 2CS-8455 being the corresponding Unit 2 valve. The dual unit Technical Specifications utilize a convention of identifying valves: without the unit designator if the remainder of the tag number is applicable to both units, with the unit designator if the tag is only applicable to one unit.

When a specification is shared per 3.0.5a, the ACTION section contains the identifier "(Units 1 and 2)".

3/4.1 REACTIVITY CONTROL SYSTEMS

3/4.1.1 BORATION CONTROL

SHUTDOWN MARGIN - T_{avg} GREATER THAN 200°F

LIMITING CONDITION FOR OPERATION

3.1.1.1 The SHUTDOWN MARGIN shall be greater than or equal to ~~1.6% Δk/k~~.

1.6% Δk/k for Unit 1 (1.3% Δk/k for Unit 2)

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

ACTION:

With the SHUTDOWN MARGIN less than ~~1.6% Δk/k~~, immediately initiate and continue boration at greater than or equal to 30 gpm of a solution containing greater than or equal to 7,000 ppm boron or equivalent until the required SHUTDOWN MARGIN is restored.

SURVEILLANCE REQUIREMENTS

4.1.1.1.1 The SHUTDOWN MARGIN shall be determined to be greater than or equal to ~~1.6% Δk/k~~:

a. Within 1 hour after detection of an inoperable control rod(s) and at least once per 12 hours thereafter while the rod(s) is inoperable. If the inoperable control rod is immovable or untrippable, the above required SHUTDOWN MARGIN shall be verified acceptable with an increased allowance for the withdrawn worth of the immovable or untrippable control rod(s);

b. When in MODE 1 or MODE 2 with K_{eff} greater than or equal to 1 at least once per 12 hours by verifying that control bank withdrawal is within the limits of Specification 3.1.3.6;

c. When in MODE 2 with K_{eff} less than 1, within 4 hours prior to achieving reactor criticality by verifying that the predicted critical control rod position is within the limits of Specification 3.1.3.6;

d. Prior to initial operation above 5% RATED THERMAL POWER after each fuel loading, by consideration of the factors of Specification 4.1.1.1.1e. below, with the control banks at the maximum insertion limit of Specification 3.1.3.6; and

*See Special Test Exceptions Specification 3.10.1.

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[a], 4[a], 5[a]	9
2. Power Range, Neutron Flux					
a. High Setpoint	4	2	3	1, 2	2
b. Low Setpoint	4	2	3	1[c], 2	2
3. Power Range, Neutron Flux High Positive Rate	4	2	3	1, 2	2
4. Power Range, Neutron Flux, High Negative Rate	4	2	3	1, 2	2
5. Intermediate Range, Neutron Flux	2	1	2	1[c], 2	3
6. Source Range, Neutron Flux					
a. Reactor Trip and Indication					
1) Startup	2	1	2	2[b]	4
2) Shutdown	2	1	2	3, 4, 5	5.1
b. Boron Dilution Flux Doubling*	2	1	2	3[h],4, 5	5.1, 5.2
7. Overtemperature N-16	4	2	3	1, 2	12
8. Overpower N-16	4	2	3	1, 2	12
9. Pressurizer Pressure--Low	4	2	3	1[d]	6[e]
10. Pressurizer Pressure--High	4	2	3	1, 2	6

*Boron Dilution Flux Doubling requirements become effective for Unit 1 six months after criticality for Cycle 3. Insert

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for page 3/4 3-2

and for Unit 2 six months after initial criticality

TABLE 3.3-1 (Continued)

TABLE NOTATIONS

[a]Only if the reactor trip breakers happen to be in the closed position and the Control Rod Drive System is capable of rod withdrawal.

[b]Below the P-6 (Intermediate Range Neutron Flux Interlock) Setpoint.

[c]Below the P-10 (Low Setpoint Power Range Neutron Flux Interlock) Setpoint.

[d]Above the P-7 (At Power) Setpoint

[e]The applicable MODES and ACTION statements for these channels noted in Table 3.3-2 are more restrictive and therefore, applicable.

[f]Above the P-8 (3-loop flow permissive) Setpoint.

[g]Above the P-7 and below the P-8 Setpoints.

[h]The boron dilution flux doubling signals may be blocked during reactor startup.*

[i]Above the P-9 (Reactor trip on Turbine trip Interlock) Setpoint.

ACTION STATEMENTS

ACTION 1 - With the number of OPERABLE channels one less than the Minimum Channels OPERABLE requirement, restore the inoperable channel to OPERABLE status within 48 hours or be in HOT STANDBY within the next 6 hours.

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

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

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

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

*Boron Dilution Flux Doubling requirements become effective for Unit 1 six months after criticality for Cycle 3.

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for Page 3/4 3-5

and for Unit 2 six months after initial criticality

TABLE 3.3-1 (Continued)

ACTION STATEMENTS (Continued)

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

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

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

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

ACTION 5.1 - With the number of OPERABLE channels one less than the Minimum Channels OPERABLE requirement, restore the inoperable channel to OPERABLE status within 48 hours or within the next hour open the reactor trip breakers and suspend all operations involving positive reactivity changes. With no channels OPERABLE complete the above actions within 4 hours.

ACTION 5.2*- With the number of OPERABLE channels one less than the Minimum Channels OPERABLE requirement, restore the inoperable channel to OPERABLE status within 48 hours or within the next hour verify either valve 1CS-8455 or valves 1CS-8560, FCV-111B, 1CS-8439, 1CS-8441, and 1CS-8453 are closed and secured in position, and verify this position at least once per 14 days thereafter. With no channels OPERABLE, complete the above actions within 4 hours and verify the positions of the above valves at least once per 14 days thereafter.

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

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

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

ACTION 7 - With less than the Minimum Number of Channels OPERABLE, within 1 hour determine by observation of the associated permissive annunciator window(s) that the interlock is in its required state for the existing plant condition, or apply Specification 3.0.3.

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*Boron Dilution Flux Doubling requirements become effective for Unit 1 six months after criticality for Cycle 3.

INSERT

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for page 3/4 3-6

and for Unit 2 six months after initial criticality

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(14)	N.A.	1, 2, 3[a], 4[a], 5[a]
2. Power Range, Neutron Flux						
a. High Setpoint	S	D(2, 4), M(3, 4), Q(4, 6), R(4, 5)	Q	N.A.	N.A.	1, 2
b. Low Setpoint	S	R(4)	S/U(1)	N.A.	N.A.	1[c], 2
3. Power Range, Neutron Flux, High Positive Rate	N.A.	R(4)	Q	N.A.	N.A.	1, 2
4. Power Range, Neutron Flux, High Negative Rate	N.A.	R(4)	Q	N.A.	N.A.	1, 2
5. Intermediate Range, Neutron Flux	S	R(4, 5)	S/U(1)	N.A.	N.A.	1[c], 2
6. Source Range, Neutron Flux	S	R(4, 13)	S/U(1), Q(9)	R(12)*	N.A.	2[b], 3, 4, 5
7. Overtemperature N-16	S	D(2, 4) M(3, 4) Q(4, 6) R(4, 5)	Q	N.A.	N.A.	1, 2
8. Overpower N-16	S	D(2, 4) R(4, 5)	Q	N.A.	N.A.	1, 2
9. Pressurizer Pressure--Low	S	R	Q(8)	N.A.	N.A.	1[d]
10. Pressurizer Pressure--High	S	R	Q	N.A.	N.A.	1, 2

INSERT

*Boron Dilution Flux Doubling requirements become effective for Unit 1 six months after criticality for Cycle 3.

INSERT

for page 3/4 3-8

and for Unit 2 six months after initial criticality

TABLE 4.3-1 (Continued)

TABLE NOTATIONS

[a]Only if the reactor trip breakers happen to be in the closed position and the Control Rod Drive System is capable of rod withdrawal.

[b]Below P-6 (Intermediate Range Neutron Flux Interlock) Setpoint.

[c]Below P-10 (Low Setpoint Power Range Neutron Flux Interlock) Setpoint.

[d]Above the P-7 (At Power) Setpoint.

[e]Above the P-9 (Reactor trip on Turbine trip Interlock) Setpoint.

(1) If not performed in previous 31 days.

(2) Comparison of calorimetric to excore power and N-16 power indication above 15% of RATED THERMAL POWER. Adjust excore channel and/or N-16 channel gains consistent with calorimetric power if absolute difference of the respective channel is greater than 2%. The provisions of Specification 4.0.4 are not applicable for entry into MODE 1 or 2.

(3) Single point comparison of incore to excore AXIAL FLUX DIFFERENCE above 15% of RATED THERMAL POWER. Recalibrate if the absolute difference is greater than or equal to 3%. For the purpose of these surveillance requirements, "M" is defined as at least once per 31 EFPD. The provisions of Specification 4.0.4 are not applicable for entry into MODE 1 or 2.

(4) Neutron and N-16 detectors may be excluded from CHANNEL CALIBRATION.

(5) Detector plateau curves shall be obtained and evaluated. For the Intermediate Range Neutron Flux, Power Range Neutron Flux and N-16 channels the provisions of Specification 4.0.4 are not applicable for entry into MODE 1 or 2.

(6) Incore - Excore Calibration, above 75% of RATED THERMAL POWER. For the purpose of these surveillance requirements "Q" is defined as at least once per 92 EFPD. The provisions of Specification 4.0.4 are not applicable for entry into MODE 1 or 2.

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

(8) The MODES specified for these channels in Table 4.3-2 are more restrictive and therefore applicable.

(9) Quarterly surveillance in MODES 3[a], 4[a], and 5[a] shall also include verification that permissives P-6 and P-10 are in their required state for existing plant conditions by observation of the permissive annunciator window. Quarterly surveillance shall include verification of the Boron Dilution Alarm Setpoint of less than or equal to an increase of twice the count rate within a 10-minute period.*

*Boron Dilution Flux Doubling requirements become effective for Unit 1 six months after criticality for Cycle 3. INSERT

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for page 3/4 3-11

and for Unit 2 six months after initial criticality

TABLE 4.3-1 (Continued)

TABLE NOTATIONS (Continued)

(10) Setpoint verification is not applicable.

(11) The TRIP ACTUATING DEVICE OPERATIONAL TEST shall independently verify the OPERABILITY of the undervoltage and shunt trip attachments of the reactor trip breakers.

(12) At least once per 18 months during shutdown, verify that on a simulated Boron Dilution Flux Doubling test signal the normal CVCS discharge valves close and the centrifugal charging pumps suction valves from the RWST open. *

(13) With the high voltage setting varied as recommended by the manufacturer, an initial discriminator bias curve shall be measured for each detector. Subsequent discriminator bias curves shall be obtained, evaluated and compared to the initial curves.

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

(15) Local manual shunt trip prior to placing breaker in service.

(16) Automatic undervoltage trip.

*Boron Dilution Flux Doubling requirements become effective for Unit 1 six months after criticality for Cycle 3. INSERT

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for page 3/4 3-12

and for Unit 2 six months after initial criticality

TABLE 3.3-3

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TOTAL ALLOWANCE (TA)	Z	SENSOR ERROR (S)	TRIP SETPOINT	ALLOWABLE VALUE
1. Safety Injection (ECCS, Reactor Trip, Feedwater Isolation, Control Room Emergency Recirculation, Emergency Diesel Generator Operation, Containment Vent Isolation, Station Service Water, Phase A Isolation, Auxiliary Feedwater-Motor Driven Pump, Turbine Trip, Component Cooling Water, Essential Ventilation Systems, and Containment Spray Pump).					
a. Manual Initiation	N.A.	N.A.	N.A.	N.A.	N.A.
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.	N.A.	N.A.	N.A.
c. Containment Pressure--High 1	2.7	0.71	1.7	< 3.2 psig	≤ 3.8 psig
d. Pressurizer Pressure--Low					
a. Unit 1	15.0	10.91	2.0	≥ 1820 psig	≥ 1803.6 psig
b. Unit 2	15.0	11.3	2.0	≥ 1820 psig	≥ 1803.6 psig
e. Steam Line Pressure--Low					
a. Unit 1	17.3	15.01	2.0	≥ 605 psig*	≥ 593.5 psig*
b. Unit 2	17.3	9.15	2.0	≥ 605 psig*	≥ 578.4 psig*
2. Containment Spray					
a. Manual Initiation	N.A.	N.A.	N.A.	N.A.	N.A.
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.	N.A.	N.A.	N.A.
c. Containment Pressure--High-3	2.7	0.71	1.7	< 18.2 psig	< 18.8 psig

TABLE 3.3-3 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TOTAL ALLOWANCE (TA)	Z	SENSOR ERROR (S)	TRIP SETPOINT	ALLOWABLE VALUE
4. Steam Line Isolation					
a. Manual Initiation	N.A.	N.A.	N.A.	N.A.	N.A.
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.	N.A.	N.A.	N.A.
c. Containment Pressure--High-2	2.7	0.71	1.7	≤6.2 psig	≤6.8 psig
d. Steam Line Pressure--Low					
a. Unit 1	17.3	15.01	2.0	≥605 psig*	≥593.5 psig*
b. Unit 2	17.3	9.15	2.0	≥605 psig*	≥578.4 psig*
e. Steam Line Pressure - Negative Rate--High					
a. Unit 1	8.0	0.5	0	≤100 psi**	≤ 178.7 psi**
b. Unit 2	8.0	0.25	0	≤100 psi**	≤ 178.7 psi**
5. Turbine Trip and Feedwater Isolation					
a. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.	N.A.	N.A.	N.A.
b. Steam Generator Water Level--High-High					
1) Unit 1	7.6	4.78	2.0	≤82.4% of narrow range instrument span.	≤84.3% of narrow range instrument span.
2) Unit 2	18.5	12.4	2.0	≤81.5% of narrow range instrument span.	≤83.5% of narrow range instrument span.
c. Safety Injection	See Item 1. above for all Safety Injection Trip Setpoints and Allowable Values.				

TABLE 3.3-3 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TOTAL ALLOWANCE (TA)	Z	SENSOR ERROR (S)	TRIP SETPOINT	ALLOWABLE VALUE
6. Auxiliary Feedwater					
a. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.	N.A.	N.A.	N.A.
b. Steam Generator Water Level--Low-Low					
1) Unit 1	25.0	22.08	2.0	$\geq$ 25.0% of narrow range instrument span.	$\geq$ 23.1% of narrow range instrument span.
2) Unit 2	35.4	22.2	2.0	$\geq$ 35.4% of narrow range instrument span.	$\geq$ 33.4% of narrow range instrument span.
c. Safety Injection - Start Motor Driven Pumps	See Item 1. above for all Safety Injection Trip Setpoints and Allowable Values.				
d. Loss-of-Offsite Power	N.A.	N.A.	N.A.	N.A.	N.A.
e. Trip of All Main Feedwater Pumps	N.A.	N.A.	N.A.	N.A.	N.A.
7. Automatic Initiation of ECCS Switchover to Containment Sump					
a. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.	N.A.	N.A.	N.A.
b. RWST Level--Low-Low Coincident With Safety Injection					
a. Unit 1	2.5	0.71	1.25	$\geq$ 40.0% of span	$\geq$ 38.9% of span
b. Unit 2	2.5	0.99	1.25	$\geq$ 40.0% of span.	$\geq$ 39.1% of span.
	See Item 1. above for all Safety Injection Trip Setpoints and Allowable Values.				
8. Loss of Power (6.9 kV & 480 V Safeguards System Undervoltage)					
a. 6.9 kV Preferred Offsite Source Undervoltage	N.A.	N.A.	N.A.	$\geq$ 5004 V	$\leq$ 5900 V $\geq$ 4900 V

TABLE 3.3-3 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TOTAL ALLOWANCE (TA)	Z	SENSOR ERROR (S)	TRIP SETPOINT	ALLOWABLE VALUE
8. Loss of Power (6.9 kV & 480 V Safeguards System Undervoltage) (Continued)					
b. 6.9 kV Alternate Offsite Source Undervoltage	N.A.	N.A.	N.A.	≥ 5004 V	≤ 5900 V ≥ 4900 V
c. 6.9 kV Bus Undervoltage	N.A.	N.A.	N.A.	≥ 2037 V	≥ 1935 V ≤ 3450 V
d. 6.9 kV Degraded Voltage	N.A.	N.A.	N.A.	≥ 6054 V	≥ 5933 V
e. 480 V Degraded Voltage	N.A.	N.A.	N.A.	≥ 439 V	≥ 435 V
f. 480 V Low Grid Undervoltage	N.A.	N.A.	N.A.	≥ 447 V	≥ 443 V
9. Control Room Emergency Recirculation					
a. Manual Initiation	N.A.	N.A.	N.A.	N.A.	N.A.
b. Safety Injection	See Item 1. above for all Safety Injection Trip Setpoints and Allowable Values.				
10. Engineered Safety Features Actuation System Interlocks					
a. Pressurizer Pressure, P-11					
1) Unit 1	N.A.	N.A.	N.A.	≤ 1960 psig	≤ 1975.2 psig
2) Unit 2	N.A.	N.A.	N.A.	≤ 1960 psig	≤ 1976.4 psig
b. Reactor Trip, P-4	N.A.	N.A.	N.A.	N.A.	N.A.
11. Solid State Safeguards Sequencer (SSSS)	N.A.	N.A.	N.A.	N.A.	N.A.

TABLE 3.3-4 (Continued)

TABLE NOTATIONS

* Must satisfy Gaseous Effluent Dose Rate requirements in Part I of the ODCM.

** During CORE ALTERATIONS or movement of irradiated fuel within containment.

ACTION STATEMENTS

ACTION 27 - With the number of OPERABLE channels less than the Minimum Channels OPERABLE requirement, operation may continue provided the containment ventilation valves are maintained closed. The containment pressure relief valves may only be opened in compliance with Specification 3.6.1.7 and the radioactive gaseous effluent monitoring instrumentation requirements in Part I of the ODCM.

ACTION 28 - With the number of OPERABLE channels one less than the Minimum Channels OPERABLE requirements, within 1 hour secure the Control Room makeup air supply fan from the affected intake or initiate and maintain operation of the Control Room Emergency Air Cleanup System in emergency recirculation.

ACTION 29 - With the number of OPERABLE channels less than the Minimum Channels OPERABLE requirement, comply with the ACTION requirements of Specification 3.4.5.1.

(Units 1 and 2)

INSTRUMENTATION

EXPLOSIVE GAS MONITORING INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

3.3.3.4 The explosive gas monitoring instrumentation channels shown in Table 3.3-7 shall be OPERABLE with their Alarm/Trip Setpoints set to ensure that the limits of Specification 3.11.2.1 are not exceeded.

APPLICABILITY: As shown in Table 3.3-7.

ACTION: (Units 1 and 2)

a. With an explosive gas monitoring instrumentation channel Alarm/ Trip Setpoint less conservative than required by the above specification, declare the channel inoperable and take the ACTION shown in Table 3.3-7.

b. With less than the minimum number of explosive gas monitoring instrumentation channels OPERABLE, take the ACTION shown in Table 3.3-7. Restore the inoperable instrumentation to OPERABLE status within 30 days and, if unsuccessful, prepare and submit a Special Report to the Commission pursuant to Specification 6.9.2 to explain why this inoperability was not corrected in a timely manner.

c. The provisions of Specification 3.0.3 are n . applicable.

SURVEILLANCE REQUIREMENTS

4.3.3.4 Each explosive gas monitoring instrumentation channel shown in Table 3.3-7 shall be demonstrated OPERABLE:

a. At least once per 24 hours by performance of a CHANNEL CHECK.

b. At least once per 31 days by performance of an ANALOG CHANNEL OPERATIONAL TEST, and

c. At least once per 92 days by performance of a CHANNEL CALIBRATION which shall include the use of standard gas samples in accordance with the manufacturer's recommendations.

SURVEILLANCE REQUIREMENTS

4.4.5.2.1 Reactor Coolant System leakages shall be demonstrated to be within each of the above limits by:

a. Monitoring the Reactor Coolant System Leakage Detection System required by Specification 3.4.5.1 at least once per 12 hours;

b. Measurement of the CONTROLLED LEAKAGE to the reactor coolant pump seals when the Reactor Coolant System pressure is 2235 ± 20 psig at least once per 31 days with the modulating valve fully open. The provisions of Specification 4.0.4 are not applicable for entry into MODE 3 or 4;

c. Performance of a Reactor Coolant System water inventory balance at least within 12 hours after achieving steady state operation* and at least once per 72 hours thereafter during steady state operation, except that no more than 96 hours shall elapse between any two successive inventory balances. The provisions of Specification 4.0.4 are not applicable for entry into MODES 3 or 4; and

d. Monitoring the Reactor Head Flange Leakoff System at least once per 24 hours.

4.4.5.2.2 Each Reactor Coolant System Pressure Isolation Valve specified in Table 3.4-1 shall be demonstrated OPERABLE by verifying leakage to be within its limit:

a. At least once per 18 months,

b. Prior to entering MODE 2 whenever the plant has been in COLD SHUTDOWN for 72 hours or more and if leakage testing has not been performed in the previous 9 months, except for valves 8701A, 8701B, 8702A, and 8702B.**

c. Prior to returning the valve to service following maintenance, repair or replacement work on the valve, and

d. Within 24 hours following check valve actuation due to flow through the valve.

~~e. As outlined in the ASME Code, Section XI, paragraph IWV-3427(b).~~

e. As required in Specification 4.0.5.

The provisions of Specification 4.0.4 are not applicable for entry into MODE 3 or 4.

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*T_{avg} being changed by less than 5°F/hour.

**This exception allowed since these valves have control room position indication, inadvertent opening interlocks and a system high pressure alarm.

MATERIAL PROPERTY BASIS

CONTROLLING MATERIAL: LOWER SHELL PLATE R1108-1 (UNIT 1)
INTERMEDIATE SHELL PLATE R3807-2 (UNIT 2)

INITIAL RT_{NDT}: 0°F (UNIT 1), 10°F (UNIT2)

RT_{NDT} AFTER 16 EFPY: 1/4T, 85°F (UNIT 1), 81°F (UNIT 2)
3/4T, 70°F (UNIT 1), 62°F (UNIT 2)

CURVES APPLICABLE FOR HEATUP RATES UP TO 100°F/HR FOR THE SERVICE PERIOD UP TO 16 EFPY. CONTAINS MARGIN OF 10°F AND 60 PSIG FOR POSSIBLE INSTRUMENT ERRORS.

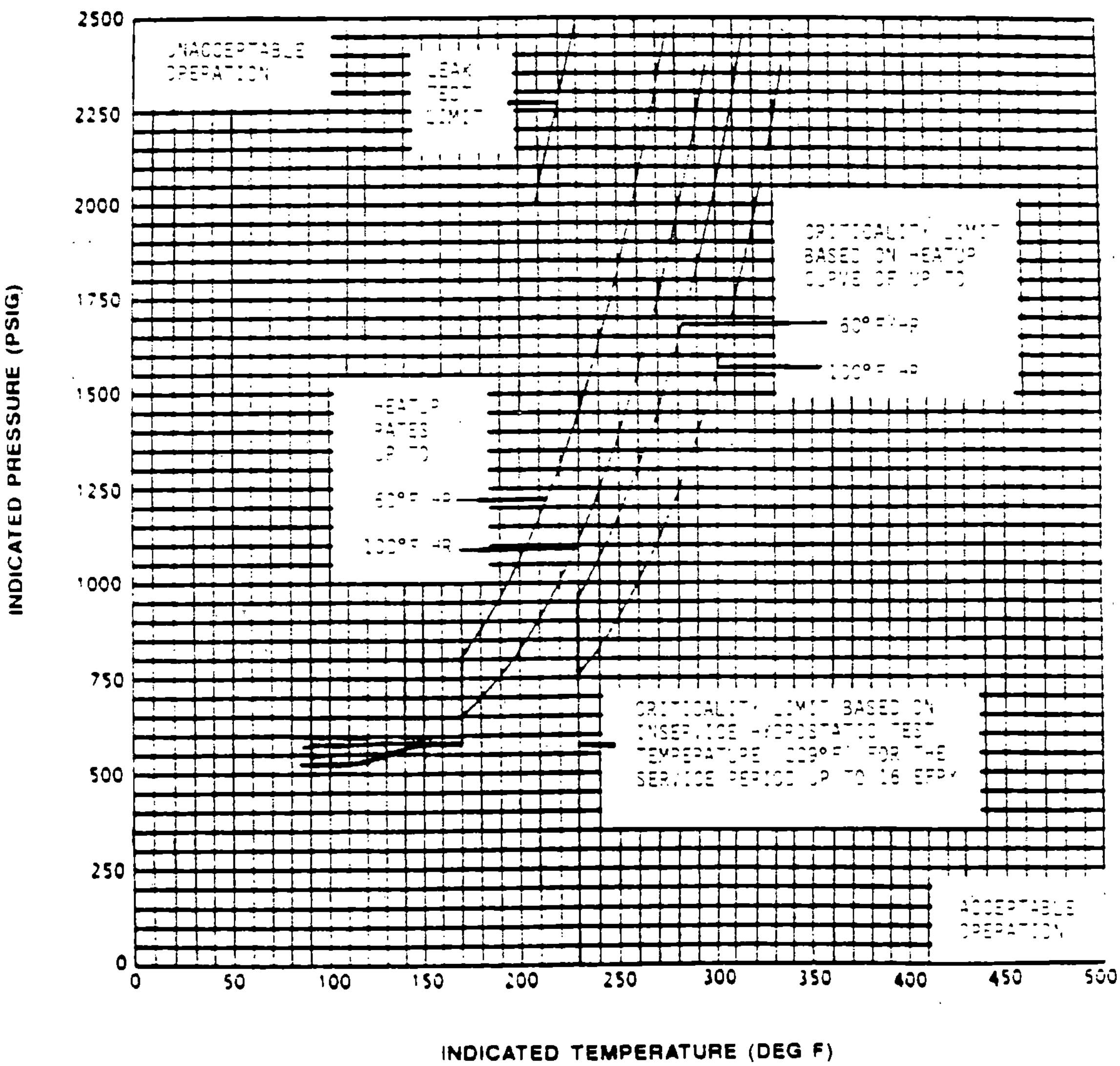

FIGURE 3.4-2

REACTOR COOLANT SYSTEM HEATUP LIMITATIONS - APPLICABLE UP TO 16 EFPY

MATERIAL PROPERTY BASIS

CONTROLLING MATERIAL: INTERMEDIATE SHELL PLATE R3807-2 (UNIT 2) LOWER SHELL PLATE R1108-1 (UNIT 1),

INITIAL RT_{NDT}: 0°F (UNIT 1), 10°F (UNIT 2)

RT_{NDT} AFTER 16 EFPY: 1/4T, 85°F (UNIT 1), 81°F (UNIT 2)

3/4T, 70°F (UNIT 1), 62°F (UNIT 2)

CURVES APPLICABLE FOR COOLDOWN RATES UP TO 100°F/HR FOR THE SERVICE PERIOD UP TO 16 EFPY. CONTAINS MARGIN OF 10°F AND 60 PSIG FOR POSSIBLE INSTRUMENT ERRORS.

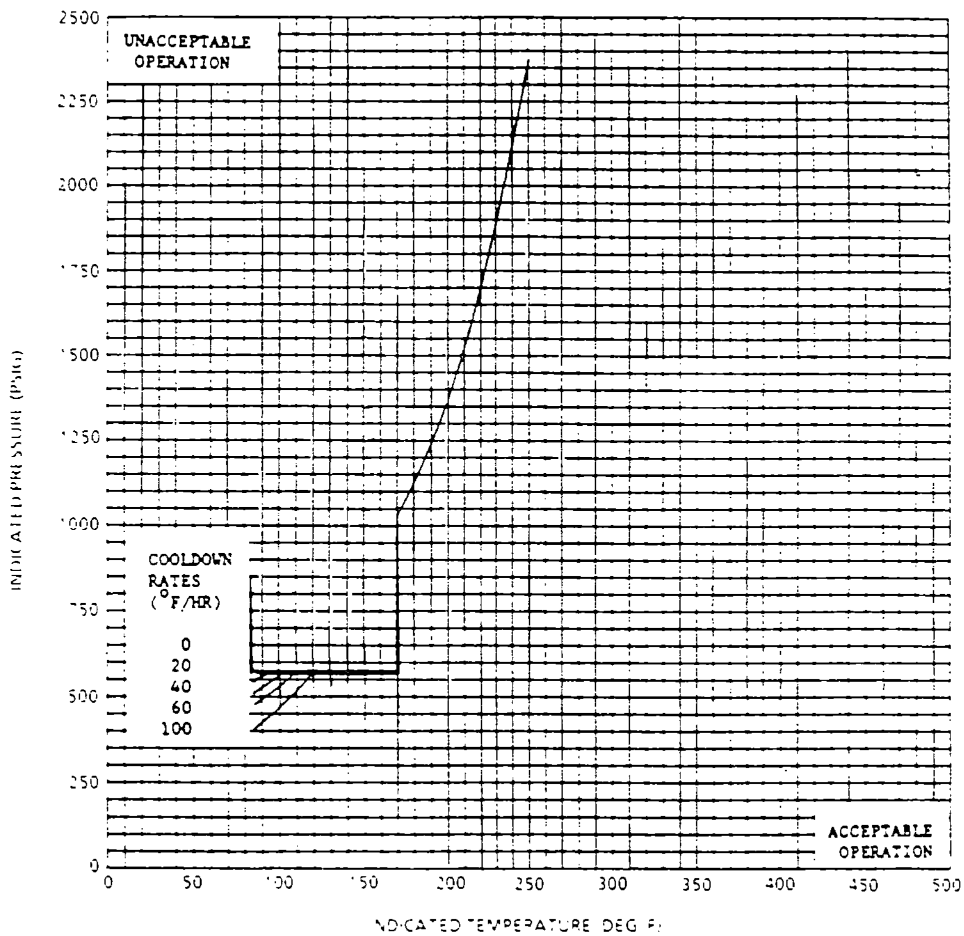

FIGURE 3.4-3

REACTOR COOLANT SYSTEM COOLDOWN LIMITATIONS - APPLICABLE UP TO 16 EFPY

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 18 months 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 test by verifying that the supplemental test result, L_c, is in accordance with the appropriate following equation:

$| L_c - (L_{am} + L_o) | \leq 0.25$ La or $| L_c - (L_{tm} + L_o) | \leq 0.25 L_t$

where L_{am} or L_{tm} is the measured Type A test leakage and L_o is the superimposed leak;

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

3) Requires that the rate at which gas is injected into the containment or bled from the containment during the supplemental test is between 0.75 L_a and 1.25 L_a; or 0.75 L_t and 1.25 L_t.

d. Type B and C tests shall be conducted with gas at a pressure not less than P_a, 48.3 psig, at intervals no greater than 24 months except for tests involving:

1) Air locks,

2) Containment ventilation isolation valves with resilient material seals,

3) Safety injection valves as specified in Specification 4.6.1.2g, and

4) Containment spray valves as specified in Specification 4.6.1.2h.

e. Air locks shall be tested and demonstrated OPERABLE by the requirements of Specification 4.6.1.3;

f. Containment ventilation isolation valves with resilient material seals shall be tested and demonstrated OPERABLE by the requirements of Specification 4.6.1.7.2 or 4.6.1.7.3, as applicable;

g. Safety injection valves 1-8809A, 1-8809B, and 1-8840 shall be leak tested with a gas at a pressure not less than P_a, 48.3 psig, or with water at a pressure not less than 1.1 P_a, at intervals no greater than 24 months;

h. Containment spray valves 1HV-4776, 1HV-4777, 1CT-142, and 1CT-145 shall be leak tested with water at a pressure not less than 1.1 P_a, at intervals no greater than 24 months; and

i. The provisions of Specification 4.0.2 are not applicable.

TABLE 3.7-1

MAXIMUM ALLOWABLE POWER RANGE NEUTRON FLUX HIGH SETPOINT WITH INOPERABLE STEAM LINE SAFETY VALVES

MAXIMUM NUMBER OF INOPERABLE SAFETY VALVES ON ANY OPERATING STEAM GENERATOR	MAXIMUM ALLOWABLE POWER RANGE NEUTRON FLUX HIGH SETPOINT (PERCENT OF RATED THERMAL POWER)
1	87
2	65
3	43

TABLE 3.7-2

STEAM LINE SAFETY VALVES PER LOOP

VALVE NUMBER				LIFT SETTING (± 1%)*	ORIFICE SIZE
LOOP 1	LOOP 2	LOOP 3	LOOP 4		
1MS-021,	058,	093,	129	1185 psig	16 in^2
1MS-022,	059,	094,	130	1195 psig	16 in^2
1MS-023,	060,	095,	131	1205 psig	16 in^2
1MS-024,	061,	096,	132	1215 psig	16 in^2
1MS-025,	062,	097,	133	1235 psig	16 in^2

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

3/4.7.5 ULTIMATE HEAT SINK

LIMITING CONDITION FOR OPERATION

3.7.5 The ultimate heat sink (UHS) shall be OPERABLE with:

a. A minimum water level at or above elevation 770 feet Mean Sea Level, USGS datum,

b. A station service water intake temperature of less than or equal to 102°F, and

c. A maximum average sediment depth of less than or equal to 1.5 feet in the service water intake channel.

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

ACTION: (Units 1 and 2)

a. With the above requirements for water level and intake temperature not satisfied, be in at least HOT STANDBY within 6 hours and in COLD SHUTDOWN within the following 30 hours.

b. With the average sediment depth in the service water intake channel greater than 1.5 feet, prepare and submit to the Commission within 30 days, pursuant to Specification 6.9.2, a Special Report that provides a record of all surveillances performed pursuant to Specification 4.7.5c and specify what measures will be employed to remove sediment from the service water intake channel.

SURVEILLANCE REQUIREMENTS

4.7.5 The ultimate heat sink shall be determined OPERABLE:

a. At least once per 24 hours by verifying the station service water intake temperature and UHS water level to be within their limits,

b. At least once per 12 months by visually inspecting the dam and verifying no abnormal degradation or erosion, and

c. At least once per 12 months by verifying that the average sediment depth in the service water intake channel is less than or equal to 1.5 feet.

3/4.7.6 FLOOD PROTECTION

LIMITING CONDITION FOR OPERATION

3.7.6 Flood protection shall be provided for all safety-related systems, components, and structures when the water level of the Squaw Creek Reservoir (SCR) exceeds 777.5 feet Mean Sea Level, USGS datum.

APPLICABILITY: At all times.

ACTION: (Units 1 and 2)

With the water level of SCR above elevation 777.5 feet Mean Sea Level, USGS datum, initiate and complete within 2 hours, the flood protection measures verifying that any equipment which is to be opened or is opened for maintenance is isolated from the SCR by isolation valves, or stop gates, or is at an elevation above 790 feet.

SURVEILLANCE REQUIREMENTS

4.7.6 The water level of SCR shall be determined to be within the limits by:

a. Measurement at least once per 24 hours when the water level is below elevation 776 feet Mean Sea Level, USGS datum.

b. Measurement at least once per 2 hours when the water level is equal to or above elevation 776 feet Mean Sea Level, USGS datum, and

c. With the water level of SCR above 777.0 feet Mean Sea Level, USGS datum, verify flood protection measures are in effect by verifying once per 12 hours that flow paths from the SCR which are open for maintenance are isolated from the SCR by isolation valves, or stop gates, or are at an elevation above 790 feet.

PLANT SYSTEMS

See Replacement 3.7.7.1 and 3.7.7.2

3/4.7.7 CONTROL ROOM HVAC SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.7 Two independent control room HVAC trains shall be OPERABLE.

APPLICABILITY: All

ACTION:

MODES 1, 2, 3 and 4:

With one control room HVAC train inoperable, restore the inoperable train to OPERABLE status within 7 days or ~~be~~ in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

MODES 5 and 6:

a. With one control room HVAC train inoperable, restore the inoperable train to OPERABLE status within 7 days or initiate and maintain operation of the remaining OPERABLE control room HVAC train in the emergency recirculation mode.

b. With both control room HVAC trains inoperable, or with the OPERABLE control room HVAC trains required to be in the emergency recirculation mode by ACTION a., not capable of being powered by an OPERABLE emergency power source, suspend all operations involving CORE ALTERATIONS or positive reactivity changes.

SURVEILLANCE REQUIREMENTS

4.7.7 Each control room HVAC train shall be demonstrated OPERABLE:

a. At least once per 31 days on a STAGGERED TEST BASIS by initiating, from the control room, flow through the HEPA filters and charcoal adsorbers and verifying that the train operates for at least 10 continuous hours with the emergency pressurization unit heaters operating;

PLANT SYSTEMS

3/4.7.7 CONTROL ROOM HVAC SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.7.1 Two independent control room HVAC trains shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4

ACTION:

With one control room HVAC train inoperable, restore the inoperable train to OPERABLE status within 7 days or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.7.7.1 Each control room HVAC train shall be demonstrated OPERABLE:

a. At least once per 31 days on a STAGGERED TEST BASIS by initiating, from the control room, flow through the HEPA filters and charcoal adsorbers and verifying that the train operates for at least 10 continuous hours with the emergency pressurization unit heaters operating;

b. At least once per 18 months or (1) after any structural maintenance on the HEPA filter or charcoal adsorber housings, or (2) following painting, fire, or chemical release in any ventilation zone communicating with the system by:

   1) Verifying that the filtration unit satisfies the in-place penetration and bypass leakage testing acceptance criteria of less than 0.05% by using the test procedure guidance in Regulatory Position C.5.a, C.5.c, and C.5.d of Regulatory Guide 1.52, Revision 2, March 1978*, and the emergency filtration unit flow rate is 8000 cfm ± 10%, and the emergency pressurization unit flow rate is 800 cfm ± 10%;

* ANSI N510-1980 and ANSI N509-1980 shall be used in place of ANSI N510-1975 and ANSI N509-1976, respectively.

SURVEILLANCE REQUIREMENTS (Continued)

2) Verifying, within 31 days after removal, that a laboratory analysis of a representative carbon sample obtained in accordance with Regulatory Position C.6.b of Regulatory Guide 1.52, Revision 2, March 1978*, meets the laboratory testing criteria of Regulatory Position C.6.a of Regulatory Guide 1.52, Revision 2, March 1978*, for a methyl iodide penetration of less than 0.2%; and

3) Verifying an emergency filtration unit flow rate of 8000 cfm ± 10% and an emergency pressurization unit flow rate of 800 cfm ± 10% during system operation when tested in accordance with ANSI N510-1980;

c. After every 720 hours of charcoal adsorber operation, by verifying, within 31 days after removal, that a laboratory analysis of a representative carbon sample obtained in accordance with Regulatory Position C.6.b of Regulatory Guide 1.52, Revision 2, March 1978*, meets the laboratory testing criteria of Regulatory Position C.6.a of Regulatory Guide 1.52, Revision 2, March 1978*, for a methyl iodide penetration of less than 0.2%;

d. At least once per 18 months by:

1) Verifying that the total pressure drop across the combined HEPA filters and charcoal adsorber banks is less than 8.0 inches water gauge while operating the emergency filtration unit at a flow rate of 8000 cfm ± 10%, and is less than 9.5 inches water gauge while operating the emergency pressurization unit at a flow rate of 800 cfm ± 10%;

2) Verifying that on a Safety Injection, Loss-of-Offsite Power, or Intake Vent-High Radiation test signal, the train automatically switches into the emergency recirculation mode of operation with flow through the HEPA filters and charcoal adsorber banks;

3) Verifying that the emergency pressurization unit maintains the control room at a positive pressure of greater than or equal to 1/8 inch Water Gauge relative to the adjacent areas, including the outside atmosphere, at a flow rate of less than or equal to 800 cfm during system operation; and

* ANSI N510-1980 and ANSI N509-1980 shall be used in place of ANSI N510-1975 and ANSI N509-1976, respectively.

SURVEILLANCE REQUIREMENTS (Continued)

4) Verifying that the heaters in the emergency pressurization units dissipate 10 ± 1 kW when tested in accordance with ANSI N510-1980;

e. After each complete or partial replacement of a HEPA filter bank in the emergency filtration unit(s), by verifying that the unit satisfies the in-place penetration and bypass leakage testing acceptance criteria of less than 0.05% in accordance with ANSI N510-1980 for a DOP test aerosol while operating the unit at a flow rate of 8000 cfm ± 10%;

f. After each complete or partial replacement of a charcoal adsorber bank in the emergency filtration unit(s), by verifying that the unit satisfies the in-place penetration and bypass leakage testing acceptance criteria of less than 0.05% in accordance with ANSI N510-1980 for a halogenated hydrocarbon refrigerant test gas while operating the unit at a flow rate of 8000 cfm ± 10%;

g. After each complete or partial replacement of a HEPA filter bank in the emergency pressurization unit(s), by verifying that the unit satisfies the in-place penetration and bypass leakage testing acceptance criteria of less than 0.05% in accordance with ANSI N510-1980 for a DOP test aerosol while operating the unit at a flow rate of 800 cfm ± 10%; and

h. After each complete or partial replacement of a charcoal adsorber bank in the emergency pressurization unit(s), by verifying that the unit satisfies the in-place penetration and bypass leakage testing acceptance criteria of less than 0.05% in accordance with ANSI N510-1980 for a halogenated hydrocarbon refrigerant test gas while operating the unit at a flow rate of 800 cfm ± 10%.

PLANT SYSTEMS

3/4.7.7 CONTROL ROOM HVAC SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.7.2 Two independent control room HVAC trains shall be OPERABLE.

APPLICABILITY: MODES 5 and 6

ACTION:

a. With one control room HVAC train inoperable, restore the inoperable train to OPERABLE status within 7 days or initiate and maintain operation of the remaining OPERABLE control room HVAC train in the emergency recirculation mode.

b. With both control room HVAC trains inoperable, or with the OPERABLE control room HVAC trains required to be in the emergency recirculation mode by ACTION a., not capable of being powered by an OPERABLE emergency power source, suspend all operations involving CORE ALTERATIONS or positive reactivity changes.

SURVEILLANCE REQUIREMENTS

4.7.7.2 Each control room HVAC train shall be demonstrated OPERABLE by performance of Surveillance Requirement 4.7.7.1.

TABLE 3.7-3

AREA TEMPERATURE MONITORING

AREA		MAXIMUM TEMPERATURE LIMIT (°F)	
		Normal Conditions	Abnormal Conditions
1.	Electrical and Control Building		
	Normal Areas	104	131
	Control Room Main Level (El. 830'-0")	80	104
	Control Room Technical Support Area (El. 840'-6")	104	104
	UPS/Battery Rooms	104	113
	Chiller Equipment Areas	122	131
2.	Fuel Building		
	Normal Areas	104	131
	Spent Fuel Pool Cooling Pump Rooms	122	131
3.	Safeguards Buildings		
	Normal Areas	104	131
	AFW, RHR, SI, Containment Spray Pump Rooms	122	131
	RHR Valve and Valve Isolation Tank Rooms	122	131
	RHR/CT Heat Exchanger Rooms	122	131
	Diesel Generator Area	122	131
	Diesel Generator Equipment Rooms	[illegible]	131
	Day Tank Room	122	131
4.	Auxiliary Building		
	Normal Areas	104	131
	CCW, CCP Pump Rooms	122	131
	CCW Heat Exchanger Area	122	131
	CVCS Valve and Valve Operating Rooms	122	131
	Auxiliary Steam Drain Tank Equipment Room	122	131
	Waste Gas Tank Valve Operating Room	122	131
5.	Service Water Intake Structure	127	131
6.	Containment Buildings		
	General Areas	120	129
	Reactor Cavity Exhaust	150	190
	CRDM Shroud Exhaust	163	172

PLANT SYSTEMS

3/4.7.11 UPS HVAC SYSTEM

OPERATING

LIMITING CONDITION FOR OPERATION

3.7.11 Two independent UPS HVAC trains shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3 and 4.

With only one UPS HVAC train OPERABLE, restore the inoperable system to OPERABLE status within 7 days or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.7.11.1 Each UPS HVAC train shall be demonstrated OPERABLE at least once per 18 months by:

a. Verifying that each UPS HVAC train starts automatically on a Safety Injection test signal.

b. Verifying that each UPS HVAC train starts automatically on a Blackout test signal.

4.7.11.2 Each UPS HVAC train shall be demonstrated OPERABLE at least once per 31 days by starting the non-operating UPS HVAC train and verifying that the train operates for at least 1 hour.

ACTION: (Units 1 and 2)

3/4.8.2 D.C. SOURCES

OPERATING

LIMITING CONDITION FOR OPERATION

3.8.2.1 As a minimum, the following D.C. electrical sources shall be OPERABLE:

INSERT

~~a. Train A - 125 volt D.C. Station Batteries BT1ED1 and BT1ED3 and at least one full-capacity charger associated with each battery, and~~

~~b. Train B - 125 volt D.C. Station Batteries BT1ED2 and BT1ED4 and at least one full-capacity charger associated with each battery.~~

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

ACTION:

With one of the required battery trains and/or required full-capacity chargers inoperable, restore the inoperable battery train and/or required full-capacity charger to OPERABLE status within 2 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.8.2.1 Each 125 V D.C. station battery and charger shall be demonstrated OPERABLE:

a. At least once per 7 days by verifying that:

1) The parameters in Table 4.8-2 meet the Category A limits, and

2) The total battery terminal voltage is greater than or equal to 128 volts on float charge.

INSERT for 3/4 8-11

a. Train A - 125 volt D.C. Station Batteries BT1ED1 and BT1ED3 for Unit 1 (BT2ED1 and BT2ED3 for Unit 2) and at least one full-capacity charger associated with each battery, and

b. Train B - 125 volt D.C. Station Batteries BT1ED2 and BT1ED4 for Unit 1 (BT2ED2 and BT2ED4 for Unit 2) and at least one full-capacity charger associated with each battery.

3/4.8.3 ONSITE POWER DISTRIBUTION

OPERATING

LIMITING CONDITION FOR OPERATION

3.8.3.1 The following electrical busses shall be energized in the specified manner:

a. Train A A.C. Emergency Busses consisting of:

1) 6900-Volt Emergency Bus 1EA1,
2) 480-Volt Emergency Bus 1EB1 from transformer T1EB1, and
3) 480-Volt Emergency Bus 1EB3 from transformer T1EB3.

b. Train B A.C. Emergency Busses consisting of:

1) 6900-Volt Emergency Bus 1EA2,
2) 480-Volt Emergency Bus 1EB2 from transformer T1EB2, and
3) 480-Volt Emergency Bus 1EB4 from transformer T1EB4.

INSERT

c. 118-Volt A.C. Instrument Bus 1PC1 and 1EC1 energized from its associated inverter connected to D.C. Bus 1ED1*;

d. 118-Volt A.C. Instrument Bus 1PC2 and 1EC2 energized from its associated inverter connected to D.C. Bus 1ED2*;

e. 118-Volt A.C. Instrument Bus 1PC3 and 1EC5 energized from its associated inverter connected to D.C. Bus 1ED3*;

f. 118-Volt A.C. Instrument Bus 1PC4 and 1EC6 energized from its associated inverter connected to D.C. Bus 1ED4*;

g. Train A 125-Volt D.C. Busses 1ED1 and 1ED3 energized from Station Batteries BT1ED1 and BT1ED3, respectively; and

h. Train B 125-Volt D.C. Busses 1ED2 and 1ED4 energized from Station Batteries BT1ED2 and BT1ED4, respectively.

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

ACTION:

a. With one of the required trains of A.C. emergency busses not fully energized, reenergize the trains within 8 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

*The inverters may be disconnected from one D.C. bus for up to 24 hours as necessary, for the purpose of performing an equalizing charge on their associated battery train provided: (1) their instrument busses are energized, and (2) the instrument busses associated with the other battery train are energized from their associated inverters and connected to their associated D.C. bus.

INSERT for page 3/4 8-15

a. Train A A.C. Emergency Busses consisting of:

1) 6900-Volt Emergency Bus 1EA1 for Unit 1 (2EA1 for Unit 2),
2) 480-Volt Emergengy Bus 1EB1 from transformer T1EB1 for Unit 1 (2EB1 from transformer T2EB1 for Unit 2), and
3) 480-Volt Emergengy Bus 1EB3 from transformer T1EB3 for Unit 1 (2EB3 from transformer T2EB3 for Unit 2), and

b. Train B A.C. Emergency Busses consisting of:

1) 6900-Volt Emergency Bus 1EA2 for Unit 1 (2EA2 for Unit 2),
2) 480-Volt Emergengy Bus 1EB2 from transformer T1EB2 for Unit 1 (2EB2 from transformer T2EB2 for Unit 2), and
3) 480-Volt Emergengy Bus 1EB4 from transformer T1EB4 for Unit 1 (2EB4 from transformer T2EB4 for Unit 2), and

c. 118-Volt A.C. Instrument Bus 1PC1 and 1EC1 for Unit 1 (2PC1 and 2EC1 for Unit 2) energized from its associated inverter connected to D.C. Bus 1ED1* for Unit 1 (2ED1* for Unit 2);

d. 118-Volt A.C. Instrument Bus 1PC2 and 1EC2 for Unit 1 (2PC2 and 2EC2 for Unit 2) energized from its associated inverter connected to D.C. Bus 1ED2* for Unit 1 (2ED2* for Unit 2);

e. 118-Volt A.C. Instrument Bus 1PC3 and 1EC5 for Unit 1 (2PC3 and 2EC5 for Unit 2) energized from its associated inverter connected to D.C. Bus 1ED3* for Unit 1 (2ED3* for Unit 2);

f. 118-Volt A.C. Instrument Bus 1PC4 and 1EC6 for Unit 1 (2PC4 and 2EC6 for Unit 2) energized from its associated inverter connected to D.C. Bus 1ED4* for Unit 1 (2ED4* for Unit 2);

g. Train A 125-Volt D.C. Busses 1ED1 and 1ED3 for Unit 1 (2ED1 and 2ED3 for Unit 2) energized from Station Batteries BT1ED1 and BT1ED3 for Unit 1 (BT2ED1 and BT2ED3 for Unit 2), respectively; and

h. Train B 125-Volt D.C. Busses 1ED2 and 1ED4 for Unit 1 (2ED2 and 2ED4 for Unit 2) energized from Station Batteries BT1ED2 and BT1ED4 for Unit 1 (BT2ED2 and BT2ED4 for Unit 2), respectively.

3/4.9 REFUELING OPERATIONS

3/4.9.1 BORON CONCENTRATION

LIMITING CONDITION FOR OPERATION

3.9.1 The boron concentration of all filled portions of the Reactor Coolant System and the refueling canal shall be maintained uniform and sufficient to ensure that the more restrictive of the following reactivity conditions is met; either:

a. A K_{eff} of 0.95 or less, or

b. A boron concentration of greater than or equal to 2000 ppm.*

Additionally, either valve 1CS-8455 or valves 1CS-8560, FCV-111B, 1CS-8439, 1CS-8441 and 1CS-8453 shall be closed and secured in position.

APPLICABILITY: MODE 6.

ACTION:

a. With the requirements a. or b. of the above not satisfied, immediately suspend all operations involving CORE ALTERATIONS or positive reactivity changes and initiate and continue boration at greater than or equal to 30 gpm of a solution containing greater than or equal to 7000 ppm boron or its equivalent until K_{eff} is reduced to less than or equal to 0.95 or the boron concentration is restored to greater than or equal to 2000 ppm, ~~whichever is the more restrictive~~.

b. If either valve 1CS-8455 or valves 1CS-8560, FCV-111B, 1CS-8439, 1CS-8441 and 1CS-8453 are not closed and secured in position, immediately suspend all operations involving CORE ALTERATIONS or positive reactivity changes and take action to isolate the dilution paths. Within 1 hour, verify the more restrictive of 3.9.1.a or 3.9.1.b or carry out Action a. above.

SURVEILLANCE REQUIREMENTS

4.9.1.1 The more restrictive of the above two reactivity conditions shall be determined prior to:

a. Removing or unbolting the reactor vessel head, and

b. Withdrawal of any control rod in excess of 3 feet from its fully inserted position within the reactor vessel.

4.9.1.2 The boron concentration of the Reactor Coolant System and the refueling canal shall be determined by chemical analysis at least once per 72 hours.

4.9.1.3 Either valve 1CS-8455 or valves 1CS-8560, FCV-111B, 1CS-8439, 1CS-8441 and 1CS-8453 shall be verified closed and secured in position by mechanical stops or by removal of air or electrical power at least once per 31 days to verify that dilution paths are isolated.

*During initial fuel load, the boron concentration limitation for the refueling canal is not applicable provided the refueling canal level is verified to be below the reactor vessel flange elevation at least once per 12 hours.

RADIOACTIVE EFFLUENTS

3/4.11.2 GASEOUS EFFLUENTS

EXPLOSIVE GAS MIXTURE

LIMITING CONDITION FOR OPERATION

3.11.2.1 The concentration of oxygen in the WASTE GAS HOLDUP SYSTEM shall be limited to less than or equal to 3% by volume whenever the hydrogen concentration exceeds 4% by volume.

APPLICABILITY: At all times.

ACTION: (Units 1 and 2)

a. With the concentration of oxygen in the WASTE GAS HOLDUP SYSTEM greater than 3% by volume but less than or equal to 4% by volume, reduce the oxygen concentration to the above limits within 48 hours.

b. With the concentration of oxygen in the WASTE GAS HOLDUP SYSTEM greater than 4% by volume and the hydrogen concentration greater than 4% by volume, immediately suspend all additions of waste gases to the system and reduce the concentration of oxygen to less than or equal to 4% by volume, then take ACTION a., above.

c. The provisions of Specifications 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.11.2.1 The concentrations of hydrogen and oxygen in the WASTE GAS HOLDUP SYSTEM shall be determined to be within the above limits by continuously monitoring the waste gases in the WASTE GAS HOLDUP SYSTEM with the hydrogen and oxygen monitors required OPERABLE by Table 3.3-7 of Specification 3.3.3.4, or by the associated ACTION statements.

RADIOACTIVE EFFLUENTS

GAS STORAGE TANKS

LIMITING CONDITION FOR OPERATION

3.11.2.2 The quantity of radioactivity contained in each gas storage tank shall be limited to less than or equal to 200,000 Curies of noble gases (considered as Xe-133 equivalent).

APPLICABILITY: At all times.

ACTION: (Units 1 and 2)

a. With the quantity of radioactive material in any gas storage tank exceeding the above limit, immediately suspend all additions of radioactive material to the tank, within 48 hours reduce the tank contents to within the limit, and describe the events leading to this condition in the next Semiannual Radioactive Effluent Release Report, pursuant to Specification 6.9.1.4.

b. The provisions of Specifications 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.11.2.2 The quantity of radioactive material contained in each gas storage tank shall be determined to be within the above limit at least once per 92 days when radioactive materials are being added to the tank.

3/4.1 REACTIVITY CONTROL SYSTEMS

BASES

3/4.1.1 BORATION CONTROL

3/4.1.1.1 and 3/4.1.1.2 SHUTDOWN MARGIN

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

1.6% $\Delta k/k$ for Unit 1 (1.3% $\Delta k/k$ for Unit 2)

SHUTDOWN MARGIN requirements vary throughout core life as a function of fuel depletion, RCS boron concentration, and RCS T_{avg}. The most restrictive condition occurs at EOL, with T_{avg} at no loading operating temperature, and is associated with a postulated steam line break accident and resulting uncontrolled RCS cooldown. In the analysis of this accident, a minimum SHUTDOWN MARGIN of ~~1.6% $\Delta k/k$~~ is required to control the reactivity transient. Accordingly, the SHUTDOWN MARGIN requirement is based upon this limiting condition and is consistent with FSAR safety analysis assumptions. With T_{avg} less than 200°F, a SHUTDOWN MARGIN of 1.3% $\Delta k/k$ provides adequate protection and is based on the results of the boron dilution accident analysis.

Since the actual overall core reactivity balance comparison required by 4.1.1.1.2 cannot be performed until after criticality is attained, this comparison is not required (and the provisions of Specification 4.0.4 are not applicable) for entry into any Operational Mode within the first 31 EFPD following initial fuel load or refueling.

3/4.1.1.3 MODERATOR TEMPERATURE COEFFICIENT

The limitations on moderator temperature coefficient (MTC) are provided to ensure that the value of this coefficient remains within the limiting condition assumed in the FSAR accident and transient analyses.

The MTC values of this specification are applicable to a specific set of plant conditions; accordingly, verification of MTC values at conditions other than those explicitly stated will require extrapolation to those conditions in order to permit an accurate comparison.

The most negative MTC value equivalent to the most positive moderator density coefficient (MDC) was obtained by incrementally correcting the MDC used in the FSAR analyses to nominal operating conditions. These corrections

MODERATOR TEMPERATURE COEFFICIENT (Continued)

involved subtracting the incremental change in the MDC associated with a core condition of all rods inserted (most positive MDC) to an all rods withdrawn condition and, a conversion for the rate of change of moderator density with temperature at RATED THERMAL POWER conditions. This value of the MDC was then transformed into the limiting End of Cycle Life (EOL) MTC value. The 300 ppm surveillance limit MTC value represents a conservative value (with corrections for burnup and soluble boron) at a core condition of 300 ppm equilibrium boron concentration and is obtained by making these corrections to the limiting EOL MTC value.

The Surveillance Requirements for measurement of the MTC at the beginning and near the end of the fuel cycle are adequate to confirm that the MTC remains within its limits since this coefficient changes slowly due principally to the reduction in RCS boron concentration associated with fuel burnup.

3/4.1.1.4 MINIMUM TEMPERATURE FOR CRITICALITY

This specification ensures that the reactor will not be made critical with the Reactor Coolant System average temperature less than 551°F. This limitation is required to ensure: (1) the moderator temperature coefficient is within it analyzed temperature range, (2) the trip instrumentation is within its normal operating range, (3) the pressurizer is capable of being in an OPERABLE status with a steam bubble, and (4) the reactor vessel is above its minimum RT_{NDT} temperature.

3/4.1.2 BORATION SYSTEMS

The Boron Injection System ensures that negative reactivity control is available during each mode of facility operation. The components required to perform this function include: (1) borated water sources, (2) charging pumps, (3) separate flow paths, (4) boric acid transfer pumps, and (5) an emergency power supply from OPERABLE diesel generators.

With the RCS average temperature above 200°F, a minimum of two boron injection flow paths are required to ensure single functional capability in the event an assumed failure renders one of the flow paths inoperable. The boration capability of either flow path is sufficient to provide a SHUTDOWN MARGIN from expected operating conditions of ~~1.6% Δk/k~~ 1.6% Δk/k for Unit 1 (1.3% Δk/k for Unit 2) after xenon decay and cooldown to 200°F. The maximum expected boration capability requirement occurs at EOL from full power equilibrium xenon conditions and requires 15,700 gallons of 7000 ppm borated water from the boric acid storage tanks or 70,702 gallons of 2000 ppm borated water from the refueling water storage tank (RWST).

3/4.4.8 PRESSURE/TEMPERATURE LIMITS

The temperature and pressure changes during heatup and cooldown are limited to be consistent with the requirements given in the ASME Boiler and Pressure Vessel Code, Section III, Appendix G and 10 CFR 50 Appendix G.

1. The reactor coolant temperature and pressure and system heatup and cooldown rates (with the exception of the pressurizer) shall be limited in accordance with Figures 3.4-2 and 3.4-3 for the service period specified thereon:

   a. Allowable combinations of pressure and temperature for specific temperature change rates are below and to the right of the limit lines shown. Limit lines for cooldown rates between those presented may be obtained by interpolation; and

   b. Figures 3.4-2 and 3.4-3 define limits to assure prevention of non-ductile failure only. For normal operation, other inherent plant characteristics, e.g., pump heat addition and pressurizer heater capacity, may limit the heatup and cooldown rates that can be achieved over certain pressure-temperature ranges.

2. These limit lines shall be calculated periodically using methods provided below,

3. The secondary side of the steam generator must not be pressurized above 200 psig if the temperature of the steam generator is below 70°F,

4. The pressurizer heatup and cooldown rates shall not exceed 100°F/h and 200°F/h, respectively, and

5. System preservice hydrotests and inservice leak and hydrotests shall be performed at pressures in accordance with the requirements of ASME Boiler and Pressure Vessel Code, Section XI.

The new 10 CFR 50, Appendix G rule addresses the metal temperature of the closure head flange and vessel flange regions. This rule states that the minimum metal temperature of the closure flange region should be at least 120°F higher than the limiting RT_{NDT} for these regions when the pressure exceeds 20% of the preservice hydrostatic test pressure (621 psig for Westinghouse plants). For Comanche Peak Unit 1, the minimum temperature of the closure flange and the vessel flange regions is 160°F since the limiting RT_{NDT} is 40°F (see Table B 3/4.4-1). The ~~Comanche Peak Unit 1~~ heatup and cooldown curves shown in Figures 3.4-2 and 3.4-3 are impacted by this new rule.

TABLE B 3/4.4-1a

UNIT I REACTOR VESSEL FRACTURE TOUGHNESS PROPERTIES

COMPONENT	GRADE	Code NO.	Cu %	Ni %	P %	T_{NDT} °F	T_{CV} 50 FT-LB 35 MIL TEMP. °F	RT_{NDT} °F	AVG. SHELF ENERGY MWD(b) FT-LB	AVG. SHELF ENERGY NMWD(c) FT-LB
Closure Hd. Dome	A533B, Cl.1	R1110-1	.09	.61	.017	10	100	40	-	126.0
Closure Hd. Torus	A533B, Cl.1	R1111-1	.08	.61	.008	-50	30	-30	-	116.5
Closure Hd. Flange	A508 Cl.2	R1102-1	-	.77	.013	40	100	40	-	119.0
Vessel Flange	A508 Cl.2	R1101-1	-	.72	.011	10	70	10	-	97.0
Inlet Nozzle	A508 Cl.2	R1105-1	.09	.82	.010	-10	50	-10	-	147.0
Inlet Nozzle	A508 Cl.2	R1105-2	.11	.84	.011	-20	40	-20	-	136.5
Inlet Nozzle	A508 Cl.2	R1105-3	.11	.81	.012	-10	50	-10	-	134.0
Inlet Nozzle	A508 Cl.2	R1105-4	.09	.82	.011	-10	50	-10	-	156.5
Outlet Nozzle	A508 Cl.2	R1106-1	-	.68	.004	-20	40	-20	-	135.0
Outlet Nozzle	A508 Cl.2	R1106-2	-	.62	.008	-10	50	-10	-	111.0
Outlet Nozzle	A508 Cl.2	R1106-3	-	.64	.005	-20	50	-10	-	135.5
Outlet Nozzle	A508 Cl.2	R1106-4		.65	.004	-20	40	-20	-	117.5
Upper Shell	A533B, Cl.1	R1104-1	.07	.61	.012	-30	100	40	-	83.0
Upper Shell	A533B, Cl.1	R1104-2	.08	.67	.011	-50	100	40	-	75.0
Upper Shell	A533B, Cl.1	R1104-3	.05	.60	.010	-20	70	10	-	107.5
Inter Shell	A533B, Cl.1	R1107-1	.06	.65	.010	-20	70	10	111.5	93.5
Inter Shell	A533B, Cl.1	R1107-2	.06	.64	.010	-20	50	-10	123.5	103.6
Inter Shell	A533B, Cl.1	R1107-3	.05	.68	.007	-20	70	10	131.0	88.0
Lower Shell	A533B, Cl.1	R1108-1	.08	.64	.008	-20	60	0	119.0	85.0
Lower Shell	A533B, Cl.1	R1108-2	.05	.59	.006	-30	80	20	124.5	78.0
Lower Shell	A533B, Cl.1	R1108-3	.07	.64	.008	-30	60	0	122.0	98.0
Bottom Hd. Torus	A533B, Cl.1	R1112-1	.13	.62	.010	-50	50	-10	-	112.0
Bottom Hd Dome	A533B, Cl.1	R1113-1	.08	.60	.010	-50	70	10	-	90.0
Inter. & Lower Shell (Long. & Girth Weld Seams)(a)	A533B, Cl.1	G1.67	.04	.17	.008	-70	-10	-70	-	150.0

a) B4 Weld Wire HT 88112 & Linde 0091 Flux Lot No. 0145
b) Major Working Direction (Longitudinal)
c) Normal to Major Working Direction (Transverse)

INSERT e

COMANCHE PEAK - UNITS 1 AND 2

TABLE B 3/4.4-1b

UNIT 2 REACTOR VESSEL FRACTURE TOUGHNESS PROPERTIES

COMPONENT	GRADE	Code NO.	Cu %	Ni %	P %	TNDT °F	Tcv 50 FT-LB 35 MIL TEMP °F	RNDT °F	AVG. SHELF ENERGY MWD (b) FT-LB	AVG. SHELF ENERGY NMWD(c) FT-LB
Closure Hd. Dome	A533B, Cl.1	R3811-1	.15	.65	.014	-40	60	0	-	131
Closure Hd. Torus	A533B, Cl.1	R3810-1	.15	.69	.011	-30	30	-30	-	143
Closure Hd. Flange	A508 Cl.2	R3802-1	-	.71	.013	40	<100	40	-	152
Vessel Flange	A508 Cl.2	R3801-1	-	.70	.009	-10	<50	-10	-	121
Inlet Nozzle	A508 Cl.2	R3803-1	-	.84	.009	-10	<50	-10	-	138
Inlet Nozzle	A508 Cl.2	R3803-2	.10	.91	.008	-20	<40	-20	-	136
Inlet Nozzle	A508 Cl.2	R3803-3	-	.91	.010	-10	<50	-10	-	146
Inlet Nozzle	A508 Cl.2	$3803-4	-	.86	.009	-20	<40	-20	-	136
Outlet Nozzle	A508 Cl.2	R3805-1	-	.64	.006	0	<60	0	-	132
Outlet Nozzle	A508 Cl.2	R3805-2	-	.66	.005	0	<60	0	-	119
Outlet Nozzle	A508 Cl.2	R3805-3	-	.66	.004	0	<60	0	-	117
Outlet Nozzle	A508 Cl.2	R3805-4	-	.67	.005	0	<60	0	-	119
Upper Shell	A533B, Cl.1	R3806-1	.05	.61	.010	-10	100	40	-	76
Upper Shell	A533B, Cl.1	R3806-2	.06	.62	.009	-30	70	10	-	87
Upper Shell	A533B, Cl.1	R3806-3	.06	.70	.007	-30	100	40	-	86
Inter Shell	A533B, Cl.1	R3807-1	.06	.64	.006	-20	<40	-20	133	108
Inter Shell	A533B, Cl.1	R3807-2	.06	.64	.007	-20	70	10	122	101
Inter Shell	A533B, Cl.1	R3807-3	.05	.60	.007	-20	40	-20	120	105
Lower Shell	A533B, Cl.1	R3816-1	.05	.59	.001	-30	30	-30	136	107
Lower Shell	A533B, Cl.1	R3816-2	.03	.65	.002	-30	60	10	131	106
Lower Shell	A533B, Cl.1	R3816-3	.04	.63	.008	-40	20	-40	139	108
Bottom Hd. Torus	A533B, Cl.1	R3813-1	.12	.65	.009	-60	0	-60	-	123
Bottom Hd. Dome	A533B, Cl.1	R3814-1	.12	.66	.009	-70	-10	-70	-	112
Weld Metal (a) (Inter. to Lower Shell Girth Seam)			.05	.03	.004	-60	<0	-60	-	96
Weld Metal (b) (Inter. to Lower Shell Long Seams)			.07	.05	.005	-50	<10	-50	-	172

a) B4 Weld Wire Ht. 88112 & Linde 124 Flux Lot No. 1061
b) B4 Weld Wire Ht. 89833 & Linde 0091 Flux Lot No. 1054
c) Normal to Major Working Direction
d) Major Working Direction

REACTOR COOLANT SYSTEM

BASES

PRESSURE/TEMPERATURE LIMITS (Continued)

HEATUP (Continued)

The use of the composite curve is necessary to set conservative heatup limitations because it is possible for conditions to exist such that over the course of the heatup ramp the controlling condition switches from the inside to the outside and the pressure limit must at all times be based on analysis of the most critical criterion.

The new 10 CFR 50 Appendix G rule addresses the metal temperature of the closure head flange and vessel flange regions. This rule states that the minimum metal temperature of the closure flange region should be at least 120 degrees-F higher than the limiting RT_{NDT} for these regions when the pressure exceeds 20 percent of the preservice hydrostatic test pressure (621 psig for Westinghouse plants). For Comanche Peak Unit 1, the minimum temperature of the closure flange and vessel flange regions is 160 degrees-F since the limiting RT_{NDT} is 40 degrees-F (see Table B 3/4.4-1). The ~~Comanche Peak Unit 1~~ cooldown curves shown in Figure 3.4-3 are impacted by this new rule, and therefore the "notch" in the cooldown curves.

Finally, the composite curves for the heatup rate data and the cooldown rate data are adjusted for possible errors in the pressure and temperature sensing instruments by the values indicated on the respective curves.

Although the pressurizer operates in temperature ranges above those for which there is reason for concern of nonductile failure, operating limits are provided to assure compatibility of operation with the fatigue analysis performed in accordance with the ASME Code requirements.

LOW TEMPERATURE OVERPRESSURE PROTECTION

The OPERABILITY of two PORVs, two RHR suction relief valves, or an RCS vent opening of at least 2.98 square inches ensures that the RCS will be protected from pressure transients which could exceed the limits of 10 CFR 50 Appendix G when one or more of the RCS cold legs are less than or equal to 350°F. Either PORV or either RHR relief valve has adequate relieving capability to protect the RCS from overpressurization when the transient is limited to either: (1) the start of an idle RCP with the secondary water temperature of the steam generator less than or equal to 50°F above the RCS cold leg temperatures, or (2) the start of two charging pumps and their injection into a water-solid RCS.

The maximum Nominal Allowed PORV Setpoint curve is derived from analyses which model the performance of the overpressure protection system for a range of mass input and heat input transients. Figure 3.4-4 is based upon this analysis including consideration of the maximum pressure overshoot beyond the PORV setpoint which can occur as a result of time delays in signal processing

BASES

3/4.6.1 PRIMARY CONTAINMENT

3/4.6.1.1 CONTAINMENT INTEGRITY

Primary CONTAINMENT INTEGRITY ensures that the release of radioactive materials from the containment atmosphere will be restricted to those leakage paths and associated leak rates assumed in the safety analyses. This restriction, in conjunction with the leakage rate limitation, will limit the EXCLUSION AREA BOUNDARY radiation doses to within the dose guideline values of 10 CFR 100 during accident conditions.

3/4.6.1.2 CONTAINMENT LEAKAGE

The limitations on containment leakage rates ensure that the total containment leakage volume will not exceed the value assumed in the safety analyses at the peak accident pressure, P_a. As an added conservatism, the measured overall integrated leakage rate is further limited to less than or equal to 0.75 L_a or 0.75 L_t, as applicable, during performance of the periodic test to account for possible degradation of the containment leakage barriers between leakage tests.

For specific system configurations, credit may be taken for a 30-day water seal that will be maintained to prevent containment atmosphere leakage through the penetrations to the environment. The following is a list of the containment isolation valves that meet this system configuration and the Maximum Allowed Leakage Rate (MALR) required to maintain the water seal for 30 days.

Valve No.	MALR (cc/hr)
1-8809A	77
1-8809B	77
1-8840	2577
1CT-142	4734
1CT-145	4734
1HV-4776	4734
1HV-4777	4734

2-8809A	75
2-8809B	73
2-8840	2382

The surveillance testing for measuring leakage rates is consistent with the requirements of 10 CFR 50 Appendix J.

3/4.6.1.3 CONTAINMENT AIR LOCKS

The limitations on closure and leak rate for the containment air locks are required to meet the restrictions on CONTAINMENT INTEGRITY and containment leak rate. Surveillance testing of the air lock seals provides assurance that the overall air lock leakage will not become excessive due to seal damage during the intervals between air lock leakage tests.

PROCEDURES AND PROGRAMS (Continued)

e. Radioactive Effluent Controls Program (Continued)

10) Limitations on the annual dose or dose commitment to any MEMBER OF THE PUBLIC due to releases of radioactivity and to radiation from uranium fuel cycle sources conforming to 40 CFR 190.

f. Radiological Environmental Monitoring Program

A program shall be provided to monitor the radiation and radionuclides in the environs of the plant. The program shall provide (1) representative measurements of radioactivity in the highest potential exposure pathways, and (2) verification of the accuracy of the effluent monitoring program and modeling of environmental exposure pathways. The program shall (1) be contained in the ODCM, (2) conform to the guidance of Appendix I to 10 CFR 50, and (3) include the following:

1) Monitoring sampling, analysis, and reporting of radiation and radionuclides in the environment in accordance with the methodology and parameters in the ODCM,

2) A Land Use Census to ensure that changes in the use of areas at and beyond the SITE BOUNDARY are identified and that modifications to the monitoring program are made if required by the results of this census, and

3) Participation in a Interlaboratory Comparison Program to ensure that independent checks on the precision and accuracy of the measurements of radioactive materials in environmental sample matrices are performed as part of the quality assurance program for environmental monitoring.

6.9 REPORTING REQUIREMENTS

ROUTINE REPORTS

6.9.1 In addition to the applicable reporting requirements of Title 10, Code of Federal Regulations, the following reports shall be submitted to the Regional Administrator of the Regional Office of the NRC unless otherwise noted.

STARTUP REPORT

6.9.1.1 A summary report of ~~plant~~ unit startup and power escalation testing shall be submitted following: (1) ~~receipt~~ of an Operating License, (2) amendment to the license involving a planned increase in power level, (3) installation of fuel that has a different design or has been manufactured by a different fuel supplier, and (4) modifications that may have significantly altered the nuclear, thermal, or hydraulic performance of the unit.

ATTACHMENT 3 TO TXX-92410

DUAL UNIT STAFFING

Contents:

Enclosures:

1. Page 6-5a, Westinghouse Standard Technical Specifications (Draft Rev. 5)
2. Page 6-5, NUREG-0694, Technical Specifications - McGuire Nuclear Station Units Nos. 1 and 2, March 1983

DESCRIPTION AND ASSESSMENT

I. BACKGROUND

Presently, the Comanche Peak Steam Electric Station (CPSES) Technical Specifications, have Administrative Controls which are written to apply only to the operation of CPSES Unit 1. The purpose of these changes is to revise those Administrative Controls necessary for the CPSES Technical Specifications to be applicable to both CPSES Unit 1 and Unit 2. These changes are patterned after the standard technical specifications and reflect CPSES specific minimum staffing requirements.

Important physical arrangement characteristics of the two units at CPSES are as follows. The two units at CPSES are constructed architecturally on the mirror image philosophy, with mirror image containment and safeguards buildings. The fuel building is a common structure located between the containment buildings and is connected to one of the containment buildings on each end of the fuel building. The auxiliary building is a combined building for both units containing shared equipment and in some cases mirror imaged auxiliary equipment. The control room is common with the Unit 1 and Unit 2 control boards being laid out in mirror image, end to end, with a common operator information area in the middle. The control room has been constructed with normal operation anticipated to be a common Shift Supervisor with separate individual unit supervisors.

II. DESCRIPTION OF TECHNICAL SPECIFICATION CHANGE REQUEST

The change delineates the required minimum shift crew composition for two units with a common control room as is the case at CPSES.

The change to page xv replaces the title for Table 6.2-1, MINIMUM SHIFT CREW COMPOSITION SINGLE UNIT FACILITY, with the appropriate title for CPSES of MINIMUM SHIFT CREW COMPOSITION TWO UNITS WITH A COMMON CONTROL ROOM. This change is consistent with the change being proposed to page 6-3.

The change to page 6-1 makes the term "unit" plural, in reference to the Plant Manager being responsible for the operation of both units at CPSES.

The changes to page 6-2 specifies that a licensed operator is required "for each unit" when fuel is in "either" reactor. Additionally while "either" unit is in MODE 1, 2, 3 or 4, at least one Senior Operator shall be in the control room.

The changes to page 6-3 replaces Table 6.2-1, MINIMUM SHIFT CREW COMPOSITION SINGLE UNIT FACILITY, with the appropriate table for CPSES of MINIMUM SHIFT CREW COMPOSITION TWO UNITS WITH A COMMON CONTROL ROOM. Additionally the descriptions for SS, SRO and RO have been modified to delete the designation of "on Unit 1" in reference to their respective operator licenses, as CPSES intends for the operators to have and maintain dual unit licenses. Two additional notes to clarify the minimum shift crew composition have been included with the new Table to further delineate the required separation of duties of those meeting the minimum shift crew composition. This change is consistent with the Westinghouse Standard Technical Specifications Draft Rev. 5.

In summary these changes are primarily of an administrative nature for the purpose of delineating the minimum shift crew, their responsibilities and their reporting relationships for two unit operation by TU Electric at CPSES.

III. ANALYSIS

The Westinghouse Standard Technical Specifications as well as the technical specifications for other nuclear stations were reviewed to determine the minimum required regulatory staffing levels applicable for CPSES minimum shift crew composition. Although significant reviews went into the development of the standard specifications, these changes were reviewed by the CPSES Operations department to confirm their acceptability for application to CPSES Units 1 and 2. The administrative changes contained within this request are consistent with the standard Technical Specifications and do not impact safety from the perspective that adequate operations personnel are maintained in order to respond appropriately to accident situations.

IV. SIGNIFICANT HAZARDS CONSIDERATION DETERMINATION

Does the proposed change:

a) Involve a significant increase in the probability or consequences of an accident previously evaluated?

The proposed changes involve administrative changes in title descriptions and responsibilities which result from the operation of two units as opposed to one at CPSES, as well as the minimum shift crew for the operation of two units. As an adequate operational staff is provided via the minimum shift crew to respond to accident situations the changes do not impact nor affect the accident analysis assumptions. Therefore, these assumptions are preserved and there is no change in the probability or consequences of any previously evaluated accident.

b) Create the possibility of a new or different kind of accident from any accident previously evaluated?

The changes to the administrative Controls section do not impact the plant or plant operating procedures.

Therefore, this change does not create the possibility of a new or different kind of accident for CPSES Unit 1.

c) Involve a significant reduction in the margin of safety, as defined by the bases of CPSES Unit 1 Technical Specifications?

The proposed changes do not impact nor affect any accidents or failure points and, therefore, do not reduce the margin of safety.

Based on the above evaluations, TU Electric concludes that the activity associated with the above described change presents no significant hazards consideration under the standards set out in 10 CFR 50.92(c) and, accordingly, a finding by the NRC of no significant hazards consideration is justified.

V. ENVIRONMENTAL EVALUATION

TU Electric has evaluated the proposed change and has determined that the change does not involve (i) a significant hazards consideration, (ii) a significant change in the types or significant increase in the amounts of any effluents that may be released offsite, or (iii) a significant increase in individual or cumulative occupational radiation exposure. Accordingly, the proposed change meets the eligibility criterion for categorical exclusion set forth in 10 CFR 51.22(c)(9); therefore, pursuant to 10 CFR 51.22(b), an environmental assessment of the proposed change is not required.

VI. REFERENCES

None

VII. PRECEDENTS

1) Page 6-5a, Westinghouse Standard Technical Specifications, Draft Rev. 5.

2) Page 6-5, NUREG-0964, Technical Specifications McGuire Nuclear Station Unit Nos. 1 and 2, March 1983.

INDEX

TWO UNITS WITH A COMMON CONTROL ROOM

ADMINISTRATIVE CONTROLS

6.1 RESPONSIBILITY

6.1.1 The Vice President, Nuclear Operations shall be responsible for overall operation of ~~the site,~~ while the Plant Manager shall be responsible for operation of the ~~unit.~~ units The Vice President, Nuclear Operations and the Plant Manager shall each delegate in writing the succession to this responsibility during their absence.

6.1.2 The Shift Supervisor (or during his absence from the control room, a designated individual, see Table 6.2-1) shall be responsible for the control room command function. A management directive to this effect, signed by the Vice President, Nuclear Operations shall be reissued to all station personnel on an annual basis.

6.2 ORGANIZATION

6.2.1 ONSITE AND OFFSITE ORGANIZATION

An onsite and an offsite organization shall be established for unit operation and corporate management, respectively. The onsite and offsite organization shall include the positions for activities affecting the safety of the nuclear power plant.

a. Lines of authority, responsibility and communication shall be established and defined from the highest management levels through intermediate levels to and including all operating organization positions. Those relationships shall be documented and updated, as appropriate, in the form of organizational charts, functional descriptions of departmental responsibilities and relationships, and job descriptions for key personnel positions, or in the equivalent forms of documentation. These requirements shall be documented in the FSAR.

b. The Vice President, Nuclear Operations shall be responsible for overall site safe operation and shall have control over those onsite activities necessary for safe operation and maintenance of the plant.

c. The Group Vice President, Nuclear Engineering and Operations shall have corporate responsibility for overall plant nuclear safety and shall take any measures needed to ensure acceptable performance of the staff in operating, maintaining, and providing technical support to the plant to ensure nuclear safety.

d. The individuals who train the operating staff and those who carry out the radiation protection and quality assurance functions may report to the appropriate manager onsite; however, they shall have sufficient organizational freedom to ensure their independence from operating pressures.

6.2.2 UNIT STAFF

The unit organization shall be subject to the following:

a. Each on-duty shift shall be composed of at least the minimum shift crew composition shown in Table 6.2-1;

UNIT STAFF (Continued)

either   for each unit   either

b. At least one licensed Operator shall be in the control room when fuel is in ~~the~~ reactor. In ~~addition,~~ while ~~the~~ unit is in MODE 1, 2, 3, or 4, at least one licensed Senior Operator shall be in the control room;

c. A Radiation Protection Technician* and a Chemistry Technician* shall be on site when fuel is in the reactor;

d. All CORE ALTERATIONS shall be observed and directly supervised by either a licensed Senior Operator or licensed Senior Operator Limited to Fuel Handling who has no other concurrent responsibilities during this operation;

e. A site Fire Brigade of at least five members* shall be maintained on site at all times. The Fire Brigade shall not include the Shift Supervisor and the two other members of the minimum shift crew necessary for safe shutdown of the unit and any personnel required for other essential functions during a fire emergency;

f. Administrative procedures shall be developed and implemented to limit the working hours of unit staff who perform safety-related functions (e.g., licensed Senior Operators, licensed Operators, Radiation Protection Technicians, auxiliary operators, and key maintenance personnel).

   The amount of overtime worked by unit staff members performing safety-related functions shall be limited in accordance with the NRC Policy Statement on working hours (Generic Letter No. 82-12); and

g. The Shift Operations Manager shall hold a Senior Reactor Operator license.

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*The Radiation Protection and the Chemistry Technicians and Fire Brigade composition may be less than the minimum requirements for a period of time not to exceed 2 hours, in order to accommodate unexpected absence, provided immediate action is taken to fill the required positions.

INSERT A

TABLE 6.2-1

MINIMUM SHIFT CREW COMPOSITION SINGLE UNIT FACILITY		
POSITION	NUMBER OF INDIVIDUALS REQUIRED TO FILL POSITION	
	MODE 1, 2, 3, or 4	MODE 5 or 6
SS	1	1
SRO	1	None
RO	2	1
AO	2	1
STA	1*	None

SS - Shift Supervisor with a Senior Operator license ~~on Unit 1~~
SRO - Individual with a Senior Operator license ~~on Unit 1~~
RO - Individual with an Operator license ~~on Unit 1~~
AO - Auxiliary Operator
STA - Shift Technical Advisor

The shift crew composition may be one less than the minimum requirements of Table 6.2-1 for a period of time not to exceed 2 hours in order to accommodate unexpected absence of on-duty shift crew members provided immediate action is taken to restore the shift crew composition to within the minimum requirements of Table 6.2-1. This provision does not permit any shift crew position to be unmanned upon shift change due to an oncoming shift crewman being late or absent.

During any absence of the Shift Supervisor from the control room while the unit is in MODE 1, 2, 3, or 4, an individual with a valid Senior Operator license shall be designated to assume the control room command function. During any absence of the Shift Supervisor from the control room while the unit is in MODE 5 or 6, an individual with a valid Senior Operator license or Operator license shall be designated to assume the control room command function.

INSERT B

~~***~~ ~~*~~The STA position shall be manned in MODES 1, 2, 3, and 4 unless the Shift Supervisor or the individual with a Senior Operator license meets the qualifications described in Option 1 of the Commission Policy Statement on Engineering Expertise (50 FR 43621, October 28, 1985).

INSERT A

for Page 6-3

MINIMUM SHIFT CREW COMPOSITION
TWO UNITS WITH A COMMON CONTROL ROOM

POSITION	NUMBER OF INDIVIDUALS REQUIRED TO FILL POSITION		
	BOTH UNITS IN MODE 1,2,3, or 4	BOTH UNITS IN MODE 5 or 6 or DEFUELED	ONE UNIT IN MODE 1, 2, 3, or 4 AND ONE UNIT IN MODE 5 or 6 or DEFUELED
SS	1	1	1
SRO	1	none**	1
RO	3*	2*	3*
AO	3*	3*	3*
STA	1***	none	1***

INSERT B

For Page 6-3

*At least one of the required individuals must be assigned to the designated position for each unit.

**At least one licensed Senior Operator or licensed Senior Operator Limited to Fuel Handling must be present during CORE ALTERATIONS on either unit, who has no other concurrent responsibilities.

ENCLOSURE 1

TO

ATTACHMENT 3 TO TXX-92410

Page 6-5a, Westinghouse Standard
Technical Specifications, Draft Rev. 5

TABLE 6.2-1a

MINIMUM SHIFT CREW COMPOSITION

TWO UNITS WITH A COMMON CONTROL ROOM

POSITION	NUMBER OF INDIVIDUALS REQUIRED TO FILL POSITION		
	BOTH UNITS IN MODE 1, 2, 3, or 4	BOTH UNITS IN MODE 5 or 6 OR DEFUELED	ONE UNIT IN MODE 1, 2, 3, or 4 AND ONE UNIT IN MODE 5 or 6 or DEFUELED
SS	1	1	1
SRO	1	none**	1
RO	3*	2*	3*
AO	3*	3*	3*
STA	1***	none	1***

SS - Shift Supervisor with a Senior Operator license
SRO - Individual with a Senior Operator license
RO - Individual with an Operator license
AO - Auxiliary Operator
STA - Shift Technical Advisor

The shift crew composition may be one less than the minimum requirements of Table 6.2-1 for a period of time not to exceed 2 hours in order to accommodate unexpected absence of on-duty shift crew members provided immediate action is taken to restore the shift crew composition to within the minimum requirements of Table 6.2-1. This provision does not permit any shift crew position to be unmanned upon shift change due to an oncoming shift crewman being late or absent.

During any absence of the Shift Supervisor from the control room while the unit is in MODE 1, 2, 3, or 4, an individual (other than the Shift Technical Advisor) with a valid Senior Operator license shall be designated to assume the control room command function. During any absence of the Shift Supervisor from the control room while the unit is in MODE 5 or 6, an individual with a valid Senior Operator license or Operator license shall be designated to assume the control room command function.

* At least one of the required individuals must be assigned to the designated position for each unit.

** At least one licensed Senior Operator or licensed Senior Operator Limited to Fuel Handling must be present during CORE ALTERATIONS on either unit, who has no other concurrent responsibilities.

*** The STA position shall be manned in MODES 1, 2, 3, and 4 unless the Shift Supervisor or the individual with a Senior Operator license meets the qualifications for the STA as required by the NRC.

ENCLOSURE 2

TO

ATTACHMENT 3 TO TXX-92410

Page 6-5, NUREG-0964, Technical Specifications
McGuire Nuclear Station Unit Nos. 1 and 2, March 1983

TABLE 6.2-1

MINIMUM SHIFT CREW COMPOSITION

POSITION	NUMBER OF INDIVIDUALS REQUIRED TO FILL POSITION		
	BOTH UNITS IN MODE 1, 2, 3, or 4	BOTH UNITS IN MODE 5 or 6 OR DEFUELED	ONE UNIT IN MODE 1, 2, 3 or 4 AND ONE UNIT IN MODE 5 or 6 or DEFUELED
SS	1	1	1
SRO	1	none[b]	1
RO	3[a]	2[a]	3[a]
AO	3[a]	3[a]	3[a]
STA	1	none	1

SS - Shift Supervisor with a Senior Operator license
SRO - Individual with a Senior Operator license
RO - Individual with an Operator license
AO - Auxiliary operator
STA - Shift Technical Advisor

a/ At least one of the required individuals must be assigned to the designated position for each unit.

b/ At least one licened Senior Operator or licensed Senior Operator Limited to Fuel Handling must be present during CORE ALTERATIONS on either unit, who has no other concurrent responsibilities.

ATTACHMENT 4 TO TXX-92410

STATION SERVICE WATER SYSTEM

CONTENTS:

ENCLOSURES:

1. Generic Letter 91-13, "Request for Information Related to the Resolution of Generic Issue 130, Essential Service Water System Failures at Multi-Unit Sites, Pursuant to 10 CFR 50.54(f)," dated September 19, 1991.

2. NUREG-0797, Safety Evaluation Report Related to the Operation of Comanche Peak Steam Electric Station, Units 1 and 2, through Supplement No. 24, April, 1990.

3. Generic Letter 89-13, "Service Water Problems Affecting Safety Related Equipment", dated July 18, 1989, and Supplement 1, dated April 4, 1990.

4. NUREG-1172, River Bend Technical Specifications, November 1985, Section 3/4.7.1.

5. NUREG-1279, Beaver Valley 2 Technical Specifications, August 1987, Section 3/4.7.4 and 3/4.7.13.

6. NUREG-0949, St. Lucie Unit 2 Technical Specifications, April 1983, Section 3/4.7.4.

7. NUREG-0973, Waterford 3 Technical Specifications, December 1984, Section 3/4.7.3.

8. NUREG-1287, Palo Verde Unit 3 Technical Specifications, November 1987, Section 3/4.7.4.

DESCRIPTION AND ASSESSMENT

I. BACKGROUND

This proposed change to the CPSES Technical Specifications is provided to assure the required OPERABILITY of Station Service Water System (SSWS) in each unit while improving the overall availability of SSWS by providing for cross-connects between the units. The present specification and Technical Requirement are appropriate while Unit 1 is operating and Unit 2 is under construction. A revised specification is needed for two operating units.

The existing CPSES Technical Specification 3/4.7.4 (Ref. 1) is consistent with the Westinghouse Standard Technical Specifications provided by the NRC to TU Electric in 1987 (Ref. 2). Technical Specification 6.8 covers the implementation of the Technical Requirements Manual (TRM) (Ref. 3), which includes Technical Requirement 3.2, Station Service Water System Operability Criteria (Ref. 4). Technical Requirement 3.2 will be superceded by this Technical Specification change.

The TRM 3.2 currently requires a Unit 2 service water pump to be available to support Unit 1 operation whenever Unit 1 is in Modes 1, 2, 3 and 4. If this condition is not satisfied, a Unit 2 pump must be restored to available status within 7 days or Unit 1 must be shut down. If only one Unit 1 service water pump is OPERABLE and neither Unit 2 service water pump is available, immediate action to restore at least one additional pump is required. Verification of Unit 2 pump availability includes an energized bus (once per day), cross-connect availability (once per day), cross-connect valve testing (quarterly) and monthly pump runs of at least 15 minutes. This technical requirement was implemented to improve SSWS reliability based on a generic probabilistic assessment of plants with two full capacity service water pumps and Information Notice No. 86-11 (See Ref. 5 and 6).

Generic Letter 91-13 (Ref. 7) proposed technical specification changes to enhance the availability of the essential service water system. TU Electric's response (Ref. 8) committed to propose a revision to the CPSES Technical Specifications and their bases to address the concerns of Generic Letter 91-13. The proposed changes are expected to be incorporated into the CPSES Unit 1 and 2 combined Technical Specifications (Ref. 9).

The normal SSWS configuration is shown on the attached sketch (Figure 1). Train isolation by two normally closed valves in series or one locked closed valve is provided to satisfy GDC-44. Unit isolation by one locked closed valve is provided to satisfy GDC-5. A service water pump for an operating unit is inoperable when its associated cross-connect is open. See Table 2 for acceptable combinations for the cross-connects.

CPSES has two 100 percent capacity SSWS pumps per unit. These four service water pumps have crosstie capability such that any service water pump may supply any other service water pump's cooling loads. The unit crosstie piping is ASME Class 3 and contains five manual gear operated butterfly valves (XSW-006, XSW-007, XSW-008, XSW-028 and XSW-029). Each train's crosstie isolation valve is maintained in the normally closed position. The Unit 1/Unit 2 crosstie valve (XSW-0006) is locked closed and will normally be maintained in the locked closed position during two unit operation in order to satisfy GDC-5 (Ref. 10, SSER 22: Section 9.2.1) except for flushing in accordance with GL 89-13 (Ref. 11). To establish a crosstie between the Units, three of these valves (including

XSW-0006) must be opened (See Figure 1).

The cross-connect valves are manual, gear operated, butterfly valves with rubber seats and are not prone to binding due to differental pressure, galvanic corrosion or hydraulic blocking above the disc. Although testing is not required by ASME Section XI, quarterly full stroke testing of these valves is consistent with Generic Letter 91-13 (Ref. 7) and the ASME Section XI (Ref. 12) requirement for Category A and B valves and thus provides reasonable assurance that the valves will be functional.

The crosstie capability requires the closure or throttling of the discharge isolation valve for the cross-connected service water pump. CPSES procedures require that both pumps be declared inoperable whenever all the cross-connect valves between them are open. For example, if XSW-0007, XSW-0006, and XSW-0028 were all open, pumps 1B and 2A would both be declared inoperable.

The basis for this Technical Specification change is the loss of service water event, which is postulated to occur in a Unit operating in MODES 1, 2, 3 or 4. If the unit is operating in an LCO Action, an additional failure (i.e. single failure) is not assumed to occur. An analysis of this event has been performed and will be documented as appropriate in Design Basis Documents. The proposed change replaces the existing specification for SSWS with the new specification developed from the guidance provided in Generic Letter 91-13 (Ref. 7). The new specifications assure SSWS OPERABILITY for each unit while providing cross-connect capability to increase SSWS availability.

II. DESCRIPTION OF TECHNICAL SPECIFICATION CHANGE REQUEST

The proposed change to TS 3/4.7.4 adds the requirement for a cross-connect between the station service water systems to be OPERABLE when either or both units are in MODE 1, 2, 3, or 4. It also adds the requirement for a minimum of one station service water pump to be OPERABLE to support the other unit in the event of a loss of essential service water event in a Unit in MODE 1, 2, 3, or 4.

TS 3/4.7.4 is divided into 3/4.7.4.1 for both Units in MODE 1, 2, 3, or 4 and 3/4.7.4.2 for only one Unit in MODE 1, 2, 3, or 4.

Table 2 provides a failure modes and effects analysis for loss of service water pump events under the provisions of the proposed Technical Specification changes. The table also describes the LCO and ACTIONS which would apply for typical modes and conditions including one unit in MODE 1, 2, 3, or 4 and one Unit defueled.

There are no surveillance testing requirements which would require the crosstie valves to be open for pump testing in accordance with Specification 4.0.5. However, Generic Letter 91-13 notes that the guidance contained in Generic Letter 89-13 and Supplement 1 (Reference 11) should be considered. Therefore, the CPSES procedures will implement periodic flushing of the cross-connect. The frequency of this flushing will be in accordance with Generic Letter 89-13, Supplement 1.

A cross-connect valve is OPERABLE if it can be cycled or is locked open. A valve that cannot be demonstrated OPERABLE by cycling is considered inoperable until the valve is surveilled in the locked open position. However, at least one cross-connect valve between units is required to be maintained closed in accordance with GDC-5 unless required for flushing or due to total loss of SSWS pumps for either unit.

The proposed Technical Specification is consistent with the Generic Letter 91-13 draft specification except as follows:

1) The proposal splits the requirements into two specifications so that a shutdown unit can satisfy the LCO without entering the action statement.

   Proposed T/S 3/4.7.4 is to be divided into 3/4.7.4.1 for both Units in MODES 1, 2, 3, or 4 and 3/4.7.4.2 for only one Unit in MODES 1, 2, 3, or 4 and the other unit in MODES 5, 6 or defueled.

2) The addition of the "defueled" Mode to cover standard refueling practices and the plant status prior to Unit 2 fuel load.

   NRC first draft Technical Specifications 3/4.7.4 (Reference 9) and Generic Letter 91-13 (Reference 7) did not cover one Unit in MODES 1, 2, 3, or 4 and one Unit in the defueled MODE.

3) The seven day allowed outage time (AOT) for the service water pump in the shutdown unit to allow for maintenance of service water pumps and cross-connects during refueling/maintenance outages.

III. ANALYSIS

The proposed Technical Specifications include all the requirements included in the existing Technical Specification. In addition, the proposed specification adds new requirements to improve the SSWS availability in the event that all SSWS is lost on one unit.

The appropriate cross-connects are closed to assure train operability, unit separation, and compliance with GDC-44 and GDC-5 (see Table 1). The appropriate cross-connects and pumps are verified OPERABLE to assure that each units SSWS is available to backup the other unit (see Table 2).

An allowed outage time (AOT) of seven days was selected for an

INOPERABLE cross-connect or SSWS pump in the shutdown unit. A PRA calculation was performed to determine the change in total core damage frequency due to the AOT variation from 72 hours to 7 days. The results show that the impact of change in AOT from 72 hours to 7 days on the calculated core damage frequency is insignificant. The equipment unavailability due to the increase in AOT is insignificant and, therefore, it has relatively no impact on the total core damage frequency.

IV. SIGNIFICANT HAZARDS EVALUATION DETERMINATION

TU Electric has evaluated the no significant hazards considerations involved with the proposed change in accordance with the three standards set forth in 10CFR50.92(c) as discussed below.

Do the proposed changes:

1. Involve a significant increase in the probability or consequences of an accident previously evaluated?

   The proposed change is related to the potential loss of essential service water event. This event has not been evaluated previously as part of the licensing or design basis for CPSES for Unit 1. As a result of this change, the availability of SSWS is increased and the probability of core damage decreased. Thus, the probability and consequences of accidents are not increased. Closure of the proper cross-connect valves ensures operation of the SSW as designed.

2. Create the possibility of a new or different kind of accident from any accident previously evaluated?

   The loss of essential service water event is not created by this proposed change because the train and unit separation are required to be maintained at all times except when flushing the cross-connects is performed in accordance with Technical Specifications and procedures. The cross-connects will be flushed prior to declaring them OPERABLE. The cross-connects are free of coatings (e.g. plasite) or any other type of material whipch could affect heat exchanger performance. Therefore, the SSWS continue to operate as designed and no new or different kind of accidents are created.

3. Involve a significant reduction in the margin of safety as defined by the bases of the Technical Specifications?

   This Technical Specification change will increase the margin of safety as described in Generic Letter 91-13.

   In the event of a total loss of SSWS in one unit at Comanche Peak, backup cooling capability is available via a cross-connect between the two units. The OPERABLE pump is manually realigned and flow balanced to provide cooling to essential heat loads. The OPERABILITY of the unit cross-connect along with a SSWS pump in the shutdown unit ensures the availability of sufficient redundant cooling capacity for the operating unit. The Limiting Condition of Operation will ensure a significant risk reduction as indicated by the analyses of a loss of Station Service Water System event. The surveillance requirements ensure the short and long-term operability of the Station Service Water System and cross-connect between the two units.

The Station Service Water System cross-connect between the two units consists of appropriate piping and cross-connect valves connecting the discharge of the SSWS pumps of the two units. By aligning the cross-connect flow path, additional redundant cooling capacity from one unit is available to the Station Service Water System of the other unit. The availability of SSWS flow from the other unit provides additional margin by providing mitigation during a loss of essential service water event.

V. ENVIRONMENTAL EVALUATION

TU Electric has evaluated the proposed change and has determined that the change does not involve (i) a significant hazards consideration, (ii) a significant change in types or significant increase in the amounts of any effluents that may be released offsite, or (iii) a significant increase in individual or cumulative occupational radiation exposure. Accordingly, the proposed change meets the eligibility criterion for categorical exclusion set forth in 10 CFR 51.92(c)(9). Therefore, pursuant to 10 CFR 51.22(b), an environmental assessment of the proposed change is not required.

VI. REFERENCES

1. NUREG-1399, Technical Specifications, Comanche Peak Steam Electric Station, Unit 1, Docket No. 50-445, April 1990.

2. Technical Specifications for Comanche Peak Steam Electric Station (CPSES) Unit 1 Docket No. 50-445, dated August 14, 1987 from Christofer Grimes (USNRC) to William G. Counsil (TU Electric).

3. TXX-89038, Technical Requirements Manual (TRM), Comanche Peak Steam Electric Station, Docket No. 50-445, from William J. Cahill, Jr. (TU Electric) to USNRC, dated January 24, 1989.

4. TXX-88848, Service Water System Reliability, CPSES Docket Nos. 50-445 and 50-446 from W. G. Counsil to USNRC dated December 16, 1988.

5. Circular 78-13, "Inoperability of Service Water Pumps," July 10, 1978.

6. IE Information Notice No. 86-11, "Inadequate Service Water Protection Against Core Melt Frequency," February 25, 1986.

7. Generic Letter 91-13, "Request for Information Related to the Resolution of Generic Issue 130, Essential Service Water System Failures at Multi-Unit Sites, Pursuant to 10 CFR 50.54(f)," dated September 19, 1991.

8. TXX-92120, Request for Information - Essential (Station) Service Water System, NRC Generic Letter 91-13, Docket Nos. 50-445 and 50-446, from William J. Cahill, Jr. to USNRC dated March 16, 1992.

9. NRC Letter from Mel B. Fields to William J. Cahill, Jr. dated March 24, 1992 regarding, "Comanche Peak Steam Electric Station Units 1 and 2 Combined Technical Specifications (TAC No. M81963)".

10. NUREG-0797, Safety Evaluation Report Related to the Operation of Comanche Peak Steam Electric Station, Units 1 and 2, through Supplement No. 24, April, 1990.

11. Generic Letter 89-13, "Service Water Problems Affecting Safety Related Equipment", dated July 18, 1989, and Supplement 1, dated April 4, 1990.

12. ASME Boiler and Pressure Vessel Code, Section XI, 1989 Ed.

VII. PRECEDENTS

The CPSES precedent for this Technical Specification is the Technical Requirements Manual provision discussed previously. The provisions for one Unit in MODES 1, 2, 3, or 4 and the other defueled are consistent between the TRM and the proposed Technical Specifications except the supporting service water pump in the defueled unit must be OPERABLE in lieu of "available".

The seven day AOT for the cross-connect valves and the supporting service water pump from a shutdown unit is consistent with the CPSES TRM 3.2 and Byron Unit 1 and Unit 2 Technical Specifications (NUREG-1113, AM-24, Section 3/4.7.4).

The AOT requirement is also consistent with the River Bend Technical Specifications (NUREG-1172, Nov. 1985, Section 3/4.7.1). River Bend has four, 100% pumps supplying two redundant essential service water loops. The AOT for only one pump OPERABLE is 72 hours which is consistent with Standard Technical Specifications. The AOT for only two pumps OPERABLE is seven (7) days.

The seven day AOT for the "third pump" is also more restrictive than that for plants with three pumps with Standard Technical Specifications which allow unlimited AOT for the third pump. (e.g. Beaver Valley 2, St. Lucie Unit 2, Waterford 3) or plants with no third pump (e.g. Palo Verde).

TABLE I

CROSS-CONNECT OPERABILITY FOR GDC-5 and GDC-44

Condition	UNIT (MODE 1-4) Train Isol. Vlv.	UNIT (MODE 1-4) Train Isol. Vlv.	CROSSTIE XSW-006 Isol. Vlv.	UNIT (MODE 1-4) Train Isol. Vlv.	UNIT (MODE 1-4) Train Isol. Vlv.
a. Normal	NC*	NC*	LC*	NC*	NC*
b. 1 Train Isolation Isolation Valve Open	LO	LC	LC*	NC*	NC*
c. The Unit Crosstie Isolation Valve Open	LC*	LC*	LO	NC*	NC*
d. b + c	LO	LC	LO	LC*	LC*
e. 1 Train Isolation Valve Open on Each Unit	LO	LC	LC*	LO	LC

* Valves may be cycled one at a time in accordance with Technical Specification requirements.

LEGEND: NC - Normally Closed
LC - Locked Closed
LO - Locked Open

TABLE 2
FAILURE ANALYSIS FOR
LOSS OF SERVICE WATER EVENTS

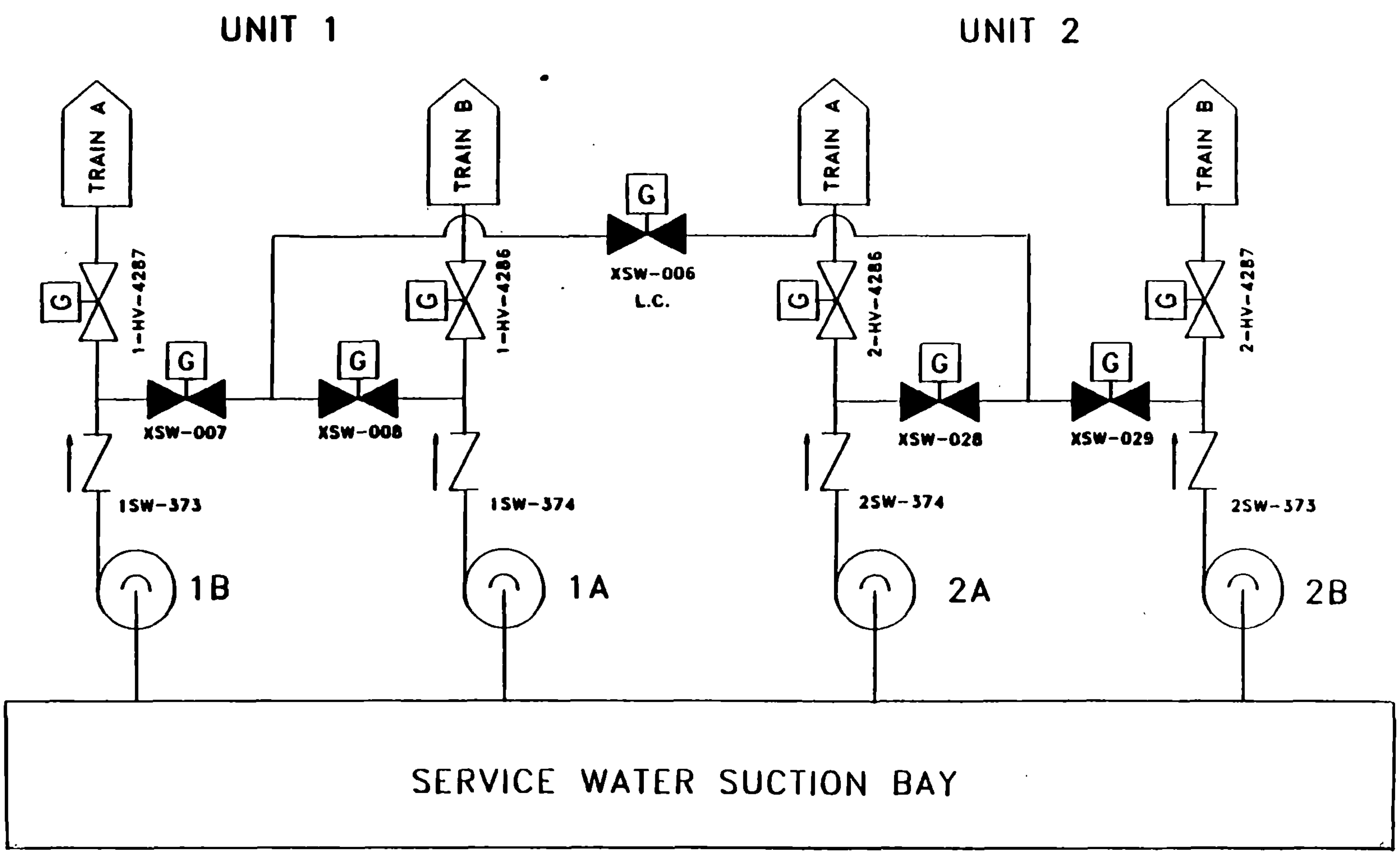
Plant Condition	Pump Status 1A	1B	2A	2B	Failure Modes	Effects
3.7.4.1, Both Units in Modes 1-4:						
All Pumps OPERABLE	0	0	0	0	Loss of one pump in either unit.	None (Automatic operation of the 100% redundant pump).
One Unit in LCO	0	I	0	0	Loss of pump 1A during 72 AOT.	Either 2A or 2B can be manually connected to Train 1A. Unit 2 would enter the LCO.
Both Units in LCO	0	I	0	I	None assumed for both units in LCO 72 hour AOT.	A pump is not available since both Units have only one Operable pump each.
3.7.4.2, One Unit (e.g. U1) in Modes 1-4 One Unit (e.g. U2 in Modes 5-6):						
All Pumps OPERABLE	0	0	0	0	Loss of one pump in either Unit.	None (Automatic operation of the 100% redundant pump).
Unit 1 in LCO Action, Both Unit 2 Pumps Available	0	I	0	0	Loss of pump 1A during 72 hrs AOT.	Pump 2A or 2B can be manually connected to Train 1A.
Unit 1 in LCO Action, One Unit 2 pump Available	0	I	0	I	Loss of Pump 1A during 72 hrs AOT.	Pump 2A can provide essential cooling for both units.

TABLE 2
FAILURE ANALYSIS FOR
LOSS OF SERVICE WATER EVENTS

Plant Condition	Pump Status 1A	1B	2A	2B	Failure Modes	Effects
Unit 1 in LCO Action, Unit 2 in LCO Action	0	I	0	I	Loss of pump 1A during 72 hr. AOT coincident with U2 in 7 day AOT is not assumed.	A Unit 2 pump is not available. The unavailability of a redundant pump (e.g. Train 1B) is limited to 72 hrs. which is equivalent to the both Units in LCO action, above, for Modes 1-4.
3.7.4.2, One Unit (e.g. U1) in Modes 1-4 and One Unit (e.g. Unit 2) defueled:						
Unit 1 pumps OPERABLE	0	0	0	I	Loss of one pump.	None (Automatic operation of the 100% redundant pump).
Unit 1 in LCO Action, Both Unit 2 Pumps Available	0	I	0	0	Loss of pump 1A during 72 hr. AOT.	Pump 2A or 2B can be manually connected to Train 1A.
Unit 1 in LCO Action, One Unit 2 Pump Available	0	I	0	I	Loss of pump 1A during 72 hr. AOT	Pump 2A can be manually connected to Train 1A.
Unit 1 in LCO Action Unit 2 in LCO Action	0	I	I	I	Loss of pump 1A during 72 hr. AOT coincident with Unit 2 in 7 day AOT is not assumed	The unavailability of a redundant pump (e.g. Train 1B) is limited to 72 hrs. which is equivalent to the both Units in LCO action, above, for Modes 1-4.

Legend: 0 - OPERABLE (AND AVAILABLE)
I - INOPERABLE (OR NOT AVAILABLE)

CPSES SERVICE WATER SYSTEMS



(See Table 1 for acceptable valve positions.)

3/4.7.4 STATION SERVICE WATER SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.4 At least two independent station service water loops shall be OPERABLE.

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

ACTION:

With only one station service water loop OPERABLE, restore at least two loops to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.7.4 Each station service water loop shall be demonstrated OPERABLE:

a. At least once per 31 days by verifying that each valve (manual, power-operated, or automatic) servicing safety-related equipment that is not locked, sealed, or otherwise secured in position is in its correct position; and

b. At least once per 18 months during shutdown, by verifying that each station service water pump starts automatically on a Safety Injection test signal.

INSERT A

INSERT A

3/4.7 PLANT SYSTEMS

3/4.7.4 STATION SERVICE WATER SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.4.1 At least two independent station service water loops per unit and the cross-connects between the station service water systems of each unit shall be OPERABLE.

APPLICABILITY: Units 1 and 2 in MODES 1, 2, 3 and 4

ACTION:

a. With only one station service water loop in a unit OPERABLE, restore at least two loops per unit to OPERABLE status within 72 hours, or for the unit(s) with the inoperable station service water loop, be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

b. With one or more of the cross-connects inoperable within 7 days, restore the cross-connect(s) to OPERABLE status. Otherwise be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.7.4.1.1 Each station service water loop shall be demonstrated OPERABLE:

a. At least once per 31 days by verifying that each valve (manual, power-operated, or automatic) servicing safety-related equipment that is not locked, sealed, or otherwise secured in position is in its correct position; and

b. At least once per 18 months, by verifying that each station service water pump starts automatically on a Safety Injection test signal.

4.7.4.1.2 The cross-connects shall be demonstrated OPERABLE by cycling the cross-connect valves in the flow path or verifying that these valves are locked open at least once per 92 days.

INSERT A
(Continued)

PLANT SYSTEMS

LIMITING CONDITION FOR OPERATION

3.7.4.2 At least two independent station service water loops in the operating unit*, at least one station service water pump in the shutdown unit** and the cross-connects from the OPERABLE station service water pump in the shutdown unit to the station service water loops of the operating unit shall be OPERABLE.

APPLICABILITY: Unit 1 (Unit 2) in MODES 1, 2, 3 and 4
Unit 2 (Unit 1) in MODES 5, 6 and defueled

ACTION:

a. With one station service water loop in the operating unit inoperable, restore two loops in the operating unit to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

b. With one or more of the cross-connects between the OPERABLE station service water pump in the shutdown unit and the station service water loops in the operating unit inoperable within 7 days, restore the inoperable valve(s) to OPERABLE status. Otherwise place the operating unit in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

c. If neither station service water pump in the shutdown unit is OPERABLE, restore at least one pump to OPERABLE status within 7 days or place the operating unit in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.7.4.2.1 Each station service water loop in the operating unit shall be demonstrated OPERABLE per the requirements of Specification 4.7.4.1.1.

4.7.4.2.2 The cross-connect(s) between the OPERABLE station service water pump in the shutdown unit and the station service water loops in the operating unit shall be demonstrated OPERABLE by cycling the cross-connect valves in the flow path or verifying that these valves are locked open at least once per 92 days.

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* A Unit in MODE 1, 2, 3 or 4 is designated as the "operating unit".
** A unit in MODE 5, 6 or defueled is designated as the "shutdown unit".

3/4.7.3 COMPONENT COOLING WATER SYSTEM

The OPERABILITY of the Component Cooling Water System ensures that sufficient cooling capacity is available for continued operation of safety-related equipment during normal and accident conditions. The redundant cooling capacity of this system, assuming a single failure, is consistent with the assumptions used in the safety analyses.

3/4.7.4 STATION SERVICE WATER SYSTEM

~~The~~ OPERABILITY of the Station Service Water System ensures that sufficient cooling capacity ~~is available~~ for continued operation of safety-related equipment during normal and accident ~~conditions.~~ The redundant cooling capacity of this system, assuming a single failure, is consistent ~~with the~~ assumptions used in the safety analyses.

INSERT B

3/4.7.5 ULTIMATE HEAT SINK

The limitations on the ultimate heat sink level and temperature ensure that sufficient cooling capacity is available to either: (1) provide normal cooldown of the facility or (2) mitigate the effects of accident conditions within acceptable limits.

The limitations on minimum water level is based on providing a 30-day cooling water supply to safety-related equipment without exceeding its design basis temperature and is consistent with the recommendations of Regulatory Guide 1.27, "Ultimate Heat Sink for Nuclear Plants," Rev. 2 (January 1976). The limitation on maximum temperature is based on the maximum allowable component temperatures in the Service Water and Component Cooling Water Systems, and the requirements for cooldown. The limitation on average sediment depth is based on the possible excessive sediment buildup in the service water intake channel.

3/4.7.6 FLOOD PROTECTION

The limitation of flood protection ensures that facility protective actions will be taken in the event of flood conditions. The only credible flood condition that endangers safety related equipment is from water entry into the turbine building via the circulating water system from Squaw Creek Reservoir and then only if the level is above 778 feet Mean Sea Level. This corresponds to the elevation at which water could enter the electrical and control building endangering the safety chilled water system. The surveillance requirements are designed to implement level monitoring of Squaw Creek Reservoir should it reach an abnormally high level above 776 feet. The Limiting Condition for Operation is designed to implement flood protection, by ensuring no open flow path via the Circulating Water System exists, prior to reaching the postulated flood level.

INSERT B

3/4.7.4 STATION SERVICE WATER SYSTEM

The OPERABILITY of the Station Service Water System ensures that sufficient cooling capacity is available for continued operation of safety-related equipment during normal and accident conditions. The redundant cooling capacity of this system, assuming a single failure, is consistent with the assumptions used in the safety analyses. A unit in MODE 1, 2, 3 or 4 will be designated as operating and a unit in MODE 5, 6 or defueled will be designated as shutdown with respect to the Station Service Water System.

Train isolation by two normally closed valves in series or one locked closed valve is provided to satisfy GDC-44. Unit isolation by one locked closed valve is provided to satisfy GDC-5. A pump for an operating unit is inoperable when its associated cross-connect is open.

In the event of a total loss of Station Service Water in one unit at Comanche Peak, backup cooling capability is available via a cross-connect between the two units. The OPERABLE pump is manually realigned and flow balanced to provide cooling to essential heat loads. The OPERABILITY of the unit cross-connect along with a Station Service Water pump in the shutdown unit ensures the availability of sufficient redundant cooling capacity for the operating unit. The Limiting Condition of Operation will ensure a significant risk reduction as indicated by the analyses of a loss of Station Service Water System event. The surveillance requirements ensure the short and long-term operability of the Station Service Water System and cross-connect between the two units.

The Station Service Water System cross-connect between the two units consists of appropriate piping and cross-connect valves connecting the discharge of the Station Service Water pumps of the two units. By aligning the cross-connect flow path, additional redundant cooling capacity from one unit is available to the Station Service Water System of the other unit.

A cross-connect valve is OPERABLE if it can be cycled or is locked open. A valve that cannot be demonstrated OPERABLE by cycling is considered inoperable until the valve is surveilled in the locked open position. However, at least one cross-connect valve between units is required to be maintained closed in accordance with GDC-5 unless required for flushing or due to total loss of Station Service Water pumps for either unit.

ENCLOSURE 1

TO

ATTACHMENT 4 TO TXX-92410

Generic Letter 91-13 dated September 19, 1991.

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

September 19, 1991

TO: LICENSEES AND APPLICANTS OF THE FOLLOWING PRESSURIZED-WATER REACTOR NUCLEAR POWER PLANTS:

1. Braidwood Units 1 and 2
2. Byron Units 1 and 2
3. Catawba Units 1 and 2
4. Comanche Peak Units 1 and 2
5. Cook Units 1 and 2
6. Diablo Canyon Units 1 and 2
7. McGuire Units 1 and 2

RECE

WILLIAM J.

SUBJECT: REQUEST FOR INFORMATION RELATED TO THE RESOLUTION OF GENERIC ISSUE 130, "ESSENTIAL SERVICE WATER SYSTEM FAILURES AT MULTI-UNIT SITES," PURSUANT TO 10 CFR 50.54(f) - GENERIC LETTER 91-13

DISCUSSION

The purpose of this letter is to inform affected licensees and applicants of the technical findings resulting from the NRC resolution of Generic Issue 130 (GI-130), "Essential Service Water System Failures at Multi-Unit Sites," and to request information from licensees and applicants at affected multi-unit sites relating to the applicability of certain findings regarding their facilities. Affected licensees and applicants are required to respond to the request for information contained in this letter, but no new requirements or staff positions are imposed on the affected licensees and applicants by this letter.

The essential service water system (ESWS) is important in maintaining plant safety during power operation, shutdown, and accident conditions. As part of our evaluation of loss of essential service water (LOSW), extensive analyses of this issue were performed at the Brookhaven National Laboratory (BNL). The technical findings of this effort at BNL are reported in NUREG/CR-5526, "Analysis of Risk Reduction Measures Applied to Shared Essential Service Water Systems at Multi-Unit Sites." In addition, the NRC staff performed a regulatory analysis to evaluate the safety benefits and implementation costs associated with various equipment and the administrative-type improvements that were considered. The staff's regulatory analysis is contained in NUREG-1421, "Regulatory Analysis for the Resolution of Generic Issue 130: Essential Service Water System Failures at Multi-Unit Sites." These analyses assume that the flushing and flow testing provisions of Generic Letter (GL) 89-13, "Service Water System Problems Affecting Safety-Related Equipment," will be applied to the crosstie lines as part of addressees' implementation of the resolution of GI-51, "Improving the Reliability of Open-Cycle Service Water Systems" (GL 89-13 and Supplement 1). On the basis of results of these evaluations of this generic safety issue, the NRC staff has concluded that the following administrative-type improvements would significantly enhance the availability of the ESWS in affected plants, and their implementation is warranted in view of the safety benefit to be derived and the cost of implementation:

- o Technical specification (TS) changes contained in Enclosure 1 to enhance the availability of the ESWS as applied to the design configuration of affected plants.

- o Improvement of emergency procedures for a LOSW using existing design features, specifically: (a) operating and maintaining high-pressure injection (HPI) pump integrity in the event of loss of reactor coolant pump (RCP) seals as a result of ESWS failure, and (b) testing and manipulating the ESWS crosstie between the units during a LOSW accident.

The incorporation of technical specification improvements is consistent with the Commission's Policy Statement on Technical Specification Improvements. This policy statement captures existing requirements under Criterion 3 (Mitigation of Design-Basis Accidents or Transients) or under the provisions to retain requirements that operating experience and probabilistic risk assessment are shown to be important to the public health and safety. General Design Criteria 44, 45, and 46 of 10 CFR Part 50, Appendix A, in conjunction with the probabilistic risk assessment performed under GI-130, form the technical bases for these TS and procedures improvements.

A backfit analysis of the type described in 10 CFR 50.109(a)(3) and 10 CFR 50.109(c) was performed, and a determination was made that these new TS and procedures improvements would provide a substantial increase in overall protection of the public health and safety and that the costs of implementing these improvements are justified in view of this increased protection (Enclosure 2). It should be noted that for the benefits of these improvements to be realized, the guidance contained in GL 89-13 and Supplement 1 should be considered in the context of the inter-unit crosstie. Namely, GL 89-13 states: "Redundant and infrequently used cooling loops should be flushed and flow tested periodically at the maximum design flow to ensure that they are not fouled or clogged. Other components in the service water system should be tested on a regular schedule to ensure that they are not fouled or clogged...."

Enclosure 3 contains a discussion of an additional safety enhancement identified as part of our evaluation of GI-130 involving installation of a dedicated RCP seal cooling system similar to that identified also under GI-23, "Reactor Coolant Pump Seal Failures." The final decision on the possible backfitting of additional plant improvements has been deferred until completion of GI-23; and that aspect of GI-130 is subsumed by GI-23. GI-23 will be resolved following the review of comments received based on the related Federal Register Notice published on April 19, 1991. The comment period has been extended until September 30, 1991. Enclosure 3 is provided to you for information only at this time.

INFORMATION REQUEST (10 CFR 50.54(f))

Addressees are requested to review the recommended TS and procedures improvements described in the preceding discussion and to evaluate the applicability and safety significance of those improvements at their respective facilities. On the basis of results of the recommended plant-specific evaluations, each addressee shall provide a response to the NRC pursuant to Section 182 of the Atomic Energy Act and 10 CFR 50.54(f) which indicates whether or not the recommended TS and procedures improvements are applicable to its facility, and whether or not the addressee will incorporate the TS (Enclosure 1) into its license and implement the procedures improvements. The response shall be provided to the NRC under oath or affirmation within 180 days of the date of this letter. If an addressee intends to implement the recommended TS and procedures improvements, the licensee shall include an implementation schedule as part of the response to this letter. The licensee should retain supporting documentation consistent with the records retention program at each facility.

An evaluation of the justification for this information request has been prepared in accordance with the requirements of 10 CFR 50.54(f). That evaluation concludes that the information requested is justified in view of the potential safety significance of the ESW reliability issue to be addressed with that information (Enclosure 4). Copies of NUREG-1421 and NUREG/CR-5526 are also enclosed for your information and to assist you in evaluating the applicability of this issue to your respective facilities (Enclosures 5 and 6).

A list of recently issued NRC GLs is enclosed for your information (Enclosure 7).

This request is covered by Office of Management and Budget Clearance Number 3150-0011, which expires May 31, 1994. The estimated average burden hours is 50 person hours per owner response, including assessment of the new recommendations, searching data sources, gathering and analyzing the data, and preparing the required letters. These estimated average burden hours pertain only to the identified response-related matters and do not include the time for actual implementation of the requested action. Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing this burden, to the Information and Records Management Branch (MNBB-7714), Division of Information Support Services, Office of Information Resources Management, U.S. Nuclear Regulatory Commission, Washington, D.C. 20555; and to Ronald Minsk, Office of Information and Regulatory Affairs (3150-0011), NEOB-3019, Office of Management and Budget, Washington, D.C. 20503.

If you have any questions on this matter, please contact your Project Manager.

Sincerely,

James G. Partlow
Associate Director for Projects
Office of Nuclear Reactor Regulation

Enclosures:
1. Draft Technical Specifications (3/4.7.4)
2. Backfit Analysis for GI-130
3. Background Discussion of a Deferred Safety Enhancement from GI-130 to GI-23
4. Justification Analysis [10 CFR 50.54(f)] for Generic Letter on GI-130
5. NUREG-1421
6. NUREG/CR-5526
7. List of Recently Issued NRC Generic Letters

ENCLOSURE I

DRAFT TECHNICAL SPECIFICATION

PLANT SYSTEMS

3/4.7.4 SERVICE WATER SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.4 At least two independent service water loops per unit and the crosstie between the service water systems of each unit (as applicable) shall be operable. In addition, the crosstie shall be capable of being opened [from the main control room] as a flow path between the two units.

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

ACTION:

A. Both units in Modes 1, 2, 3, or 4.

1. With one service water loop per unit OPERABLE, restore at least two loops per unit to OPERABLE status within 72 hours, or for the unit with the inoperable service water loop, be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

2. With one [or both] of the crosstie valve(s) INOPERABLE and not capable of being opened [from the control room], within 72 hours restore the valve(s) to OPERABLE status or open the affected valve(s), and maintain the affected valve(s) open; otherwise be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

B. One unit in Modes 1, 2, 3, or 4 and one unit in Mode 5 or 6.

1. Verify that at least one pump in the shut down unit is OPERABLE and available to provide service water to the operating unit. If neither service water pump in the shut down unit is OPERABLE, restore at least one pump to OPERABLE status within 72 hours, or place the operating unit in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

2. With one service water loop in the operating unit INOPERABLE, restore two loops in the operating unit to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

3. With one [or both] of the crosstie valve(s) INOPERABLE and not capable of being opened [from the control room], within 72 hours restore the valve(s) to OPERABLE status or open the affected valve(s), and maintain the affected valve(s) open; otherwise be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

DRAFT TECHNICAL SPECIFICATIONS

PLANT SYSTEMS

SURVEILLANCE REQUIREMENTS

4.7.4 Two service water loops per unit shall be demonstrated OPERABLE:

a. At least once per 31 days by verifying that each valve (manual, power-operated, or automatic) servicing safety-related equipment that is not locked, sealed, or otherwise secured in position is in its correct position.

b. At least once per 92 days by cycling crosstie valves and/or verifying that valves are locked open with power removed; and

c. At least once per 18 months during shutdown, by verifying that:

   1. Each automatic valve servicing safety-related equipment actuates to its correct position on a ______ test signal;

   2. Each service water system pump starts automatically on a ______ test signal; and

   3. Each crosstie valve is cycled or is locked open with power removed.

BASES

3/4.7.4 SERVICE WATER SYSTEM

The OPERABILITY of the service water system ensures that sufficient cooling capacity is available for continued operation of safety-related equipment during normal and accident conditions. The redundant cooling capacity of this system, assuming a single failure, is consistent with the assumptions used in the accident conditions within acceptable limits.

In the event of a total loss of service water in one unit of a two-unit site where backup cooling capacity is available via a crosstie between the two units, the OPERABILITY of the unit crosstie along with a service water pump in the shut down unit ensures the availability of sufficient redundant cooling capacity for the operating unit. These limiting conditions will ensure a significant risk reduction, as indicated by the analyses of a loss-of-service water system accident. The surveillance requirements ensure the short-term and long-term operability of the service water system and the crosstie between the two units. The service water system crosstie between the two units consists of appropriate piping, valves, and instrumentation cross-connecting the discharge of the service water pumps of the two units. By operating the crosstie, the supply of additional redundant cooling capacity from one unit is available to the service water system of the other unit.

ENCLOSURE 2

BACKFIT ANALYSIS (REFERENCE 10 CFR 50.109)

FOR GENERIC ISSUE 130

A.1 INTRODUCTION

This enclosure presents the backfit analysis for Generic Issue 130 (GI-130), "Essential Service Water System Failures at Multi-Unit Sites." The technical findings for GI-130 are presented in NUREG/CR-5526, and the regulatory analysis is presented in NUREG-1421. The studies apply to 14 reactor units at seven sites and indicate that essential service water system (ESWS) failures at these plants are a significant contributor to the overall plant risk. As a consequence of these technical findings, and based on the cost/benefit analyses performed, the staff has determined that these 14 plants may need to modify technical specifications (TS) to enhance the availability of the ESWS and to institute procedures to assure the integrity of the high-pressure injection (HPI) pump in the event of RCP seal failure as a result of loss of essential service water (LOSW), as well as procedures to test and manipulate the ESWS crosstie between the two units during a LOSW accident.

The estimated benefit from the identified safety enhancements is a reduction in the core damage frequency and a reduction in the associated risk of offsite radioactive releases as a result of ESW failure. The reduction of risk to the public (per plant lifetime) is estimated to be 4141 person-rem (best estimate numbers used) and supports the conclusion that these safety enhancements provide a substantial increase in the overall protection of the public health and safety. Also, the direct and indirect costs of implementation are justified in view of this increased protection.

As discussed in NUREG-1421, when considered individually, most of the alternatives analyzed for reducing the risk associated with this issue would be cost-effective in meeting the $1000/person-rem guideline. The objective of the GI-130 resolution is that the risk from loss of the ESWS be reduced consistent with the two basic requirements of the backfit rule that the corrective alternatives be both substantial and cost-effective.

One of the potential improvements consisting of improvements in TS and emergency procedures was shown to be capable of reducing the core damage frequency (CDF) from loss of ESW (1.5E-04/RY) by 17 percent (or by approximately 3.0E-05/RY) in a cost-effective manner. The staff recognizes the uncertainties in these estimates, and in recognition of the potentially substantial risk reductions (over 4000 person-rem per plant lifetime), the staff believes that significant safety improvements can be achieved by low cost changes in TS and procedures. This is deemed to be consistent with the provisions of the backfit rule.

The overall approach to arriving at the proposed resolution considered both the numerical results of the cost-benefit analysis and the spectrum and type of potential improvements available for potential risk reduction for loss-of-service-water sequences. Those alternatives that could reduce the number of occurrences of the LOSW initiators would be desirable from the prevention perspective. Those alternatives that would help to reduce the consequences of an LOSW would be desirable from the mitigation perspective. The improvements in the TS would assist on the prevention side, while the improved procedures would provide a blend of both prevention and mitigation capabilities.

The conclusion of this backfit analysis is that a substantial increase in the protection of the public health and safety will be derived from backfitting of the ESWS improvements and that the backfit is justified in view of the favorable cost/benefit ratios. In the following sections of this backfit analysis, the nine factors stipulated by 10 CFR 50.109(c) to be used in the determination of backfitting are addressed.

A.2 ANALYSIS OF 10 CFR 50.109(c) FACTORS FOR "ALTERNATIVE 5"

A.2.1 Objective

The objective of Alternative 5 (the proposed backfit) is to improve the performance of the ESW system by providing a blend of both prevention and mitigation capabilities. This backfit will be applicable to all the pressurized-water reactor (PWR) plants (14 units) covered by GI-130.

A.2.2 Licensee Activities

To implement "Alternative 5," each licensee would modify TS in accordance with Enclosure 1 to this generic letter, as well as implement procedures for operating and maintaining HPI pump integrity and testing and manipulating the ESWS crosstie between units during a LOSW event.

A.2.3 Public Risk Reduction

Backfitting in accordance with the proposed alternative will yield a reduction in the incidence of public risk from the accidental offsite release of radioactive materials of 4141 person-rem (best-estimate) per plant with an average remaining life of 30 years. This backfit will reduce the core damage frequency from an LOSW by 17 percent (or by approximately 3.0E-05/RY).

As detailed in Chapter 6 of NUREG-1421, the staff recognizes the uncertainties in these estimates and has considered both the numerical results of the cost-benefit analysis as well as the spectrum and type of potential improvements for risk reductions associated with LOSW sequences.

A.2.4 Occupational Exposure

The radiological operational exposure is negligible and, therefore, the implementation of Alternative 5 will not result in any increase in the radiological exposure to facility employees.

A.2.5 Installation Costs

The best estimate total cost per reactor associated with Alternative 5 is $83,000. When the onsite averted costs are taken into account, this alternative results in a net savings.

A.2.6 Potential Safety Impact

A number of generic safety issues related to GI-130 have been in various stages of resolution, including some that have already been resolved. The relation of these issues to GI-130 is as follows:

- GI-23, "Reactor Coolant Pump Seal Failures" -- This generic safety issue addresses the same possible improvements as Alternative 6 and, in part, Alternative 7 of GI-130. The staff's current understandings, technical findings, and potential recommendations regarding GI-23 were issued for public comment. On the basis of the staff's current knowledge and perspective, the staff has identified an approach for the resolution of GI-23. This approach is contained in Draft Regulatory Guide DG-1008.

  An objective of the identified approach for the resolution of GI-23 is to reduce the risk of severe accidents associated with RCP seal failure by reducing the probability of seal failure, or to demonstrate that the risk is not significant, thus assuring that it is a relatively small contributor to total core damage frequency. The proposed means of doing so entails the installation of a separate and independent cooling system for the RCP seals. Hence, implementation of the proposed GI-23 resolution could provide a substantial portion of the proposed GI-130 resolution. As such, the resolution of GI-130 is coordinated with the resolution of GI-23 by allowing the installation of a backup RCP seal cooling system to be deferred to the resolution of GI-23 pending the receipt and review of public comments. It is expected that information developed as a result of the submittal of public comments will be helpful in our efforts to better understand the performance of the RCP seals under loss of seal cooling conditions.

- GI-51, "Improving the Reliability of Open-Cycle Service-Water Systems" -- The resolution of this generic safety issue was reported in August 1989 and its imposition began with the issuance of Generic Letter 89-13 and Supplement 1. Implementation of the GI-51 entails the implementation of a series of surveillance, control, and test requirements to ensure that the ESWS of all nuclear power plants are in compliance with all applicable licensing requirements.

  During the review of the operational experience data of GI-130, credit was taken for a corrective measure as a result of the resolution of GI-51 by excluding those events that involved biofouling of the ESW. Hence, GI-51 has no direct impact on GI-130.

o GI-153, "Loss of Essential Service Water in LWRs" has been assigned NRC staff resources for its resolution. Its purpose is to assess this issue for all light-water reactors (LWRs) not already covered by GI-130. Insights gained by the evaluation of GI-153 are expected to be useful in confirming and/or supplementing the technical findings of GI-130.

Of interest to the decision process on this generic issue are the insights and reviews available in related probabilistic risk assessment (PRA) documentation in the open literature. The PRA work available in NUREG-1150, "Severe Accident Risks: An Assessment for Five U.S. Nuclear Power Plants" (plus supporting documentation) is a source of extensive risk analyses information that might be used for an understanding of ESW vulnerabilities. An examination of the NUREG-1150 documentation of the three PWRs that were studied indicates that the analyst thought that the ESW redundancy for two of the three PWRs was large enough that a complete loss of ESW as an event initiator was deemed not credible (eight pumps are available at Sequoyah, Units 1 and 2). None of the five plants in the NUREG-1150 study is a GI-130 plant; however, it is worthwhile to note that one of the PWRs (Zion) identified the service water contribution to CDF to be substantial (approximately 1.5E-04/RY). This contribution for Zion was approximately 42 percent of the total core damage frequency from all causes.

Another PRA work available in the open literature is NSAC-148, "Service Water Systems and Nuclear Plant Safety," dated May 1990. Although NSAC-148 is only a compilation of earlier PRA results for six plants performed by the industry, it is useful to note that a greater appreciation of the service water system's contribution to plant risk has moved the industry to initiate a program to improve service water performance. The limited guidance available in NSAC-148 is a step in the right direction. The wide range of core damage frequencies (from LOSW) at the six plants studied suggests the large variability in plant-specific ESW configurations. The average CDF from LOSW for the six plants was 6.55E-05/RY, with a range of 2.33E-04/RY-to-"negligible" contribution. Although many details of these six PRAs are not included in NSAC-148, and therefore, must be considered to be used only with great caution, the overall message that the service water system provides an important safety function that could be a substantial contributor to overall plant risk tends to lend added credence to the GI-130 conclusions.

A.2.7 <u>NRC Costs</u>

Implementation of Alternative 5 is estimated at $21,000 (best estimate). This estimate assumes minimal resources for review of the generic letter responses.

A.2.8 <u>Facility Differences</u>

Alternative 5 is applicable to all 14 plants covered by this study, regardless of age or design. Other PWR and BWR plants that are not included under the resolution of GI-130 will be evaluated under GI-153, "Loss of Essential Service Water in LWRs."

A.2.9 Term of Requirements

This represents the final resolution of GI-130. Alternative No. 6 entailing the installation of an independent RCP seal cooling system has been subsumed under the resolution of GI-23.

ENCLOSURE 3

BACKGROUND DISCUSSION OF A DEFERRED SAFETY ENHANCEMENT

FROM GI-130 TO GI-23

(INSTALLATION OF A DEDICATED RCP SEAL COOLING SYSTEM)

As identified in NUREG-1421, "Regulatory Analysis for the Resolution of Generic Issue 130: Essential Service Water System Failures at Multi-Unit Sites," a combination of potential improvements consisting of the installation of a backup, dedicated RCP seal cooling system, and improvements in technical specifications (TS) and procedures are shown to be capable of substantial risk reduction. The specific features of such a backup, dedicated RCP seal cooling system would be as follows:

- Single high pressure pump, 50-100 gpm capacity
- Dedicated water storage tank with capacity to last at least 8-10 hours
- AC-independent (non-seismic) pump
- No support system cooling required
- Once-through RCP seal heat removal

Limited plant-specific information obtained through the existing literature (FSARs, and so forth), site visits, or discussions with licensees have indicated that a number of the units covered by GI-130 already have plant-unique features that could be responsive to this generic safety enhancement. Rather than attempting to perform a series of PRAs tailored to each of the 14 units, the NRC encourages each licensee or applicant to review the plant-specific features (if any) that could be credited with departing from the generic (representative) base case plant configuration modelled in NUREG/CR-5526. In addition, other design alternatives may also be considered utilizing arrangements different from that of the high-pressure pump seal injection.

One such alternative would provide flow through the RCP thermal barrier heat exchangers by connecting the fire water system into the component cooling water (CCW) lines. Most fire water systems have one diesel-driven fire water pump, which usually is independent of the ESWS.

Generic Issue 23, "Reactor Coolant Pump Seal Failures," deals with this recommendation also, and specific guidance for resolving that generic issue is given in proposed Regulatory Guide DG-1008. While awaiting completion of public review and comment on draft Regulatory Guide DG-1008, resolution of this GI-130 item has been deferred until GI-23 is resolved. The reason for this deferral relates to the earlier development and promulgation of 10 CFR 50.63 (station blackout rule), which was based on an assumption regarding the magnitude of RCP seal leakage during a station blackout event. While it was left to GI-23 to validate that assumption, the resolution of GI-130 is also based on a RCP seal failure LOCA model very similar to that of GI-23, but different from the leakage assumption in 10 CFR 50.63.

ENCLOSURE 4

JUSTIFICATION ANALYSIS [10 CFR 50.54(f)]

FOR GENERIC LETTER ON GENERIC ISSUE 130

Section 50.54(f) of 10 CFR Part 50 requires that "... the NRC must prepare the reason or reasons for each information request prior to issuance to ensure that the burden to be imposed on respondents is justified in view of the potential safety significance of the issue to be addressed in the requested information." Further, Revision 4 of the Charter of the Committee To Review Generic Requirements (CRGR), dated April 1989, specifies that, at a minimum, such an evaluation shall include the following:

a. A problem statement that describes the need for the information in terms of potential safety benefit,

b. The licensee actions required and the cost to develop a response to the information request, and

c. An anticipated schedule for NRC use of the information.

The staff's 10 CFR 50.54(f) evaluation of the information request addressing the above elements follows:

a. Problem Statement That Describes the Need for the Information in Terms of Potential Safety Benefit

The recommended resolution of Generic Issue 130 (GI-130), "Essential Service Water System Failures at Multi-Unit Sites," applies to 14 reactor units at seven sites and indicates that essential service water system (ESWS) failures at these plants may significantly contribute to the overall plant risk. As a consequence of these technical findings, and based on the cost/benefit analyses performed, the staff has determined that these 14 plants may need to modify technical specifications (TS) to enhance the availability of the ESWS and to institute procedures to assure the integrity of the HPI pump in the event of RCP seal failure as a result of loss of essential service water (LOSW), as well as procedures to test and manipulate the ESWS crosstie between the two units during a LOSW accident.

The estimated benefit from the identified safety enhancements is a reduction in the core damage frequency and a reduction in the associated risk of offsite radioactive releases as a result of ESW failure. The reduction of risk to the public (per plant lifetime) is estimated to be 4141 person-rem (best estimate numbers used) and supports the conclusion that these safety enhancements provide a substantial increase in the overall protection of the public health and safety. Also, the direct and indirect costs of implementation are justified in view of this increased protection. The staff recognizes the uncertainties in these estimates, and in recognition of the potentially substantial risk reductions, the staff believes that significant safety improvements can be achieved by low cost changes in TS and procedures, consistent with the provisions of the backfit rule.

As discussed in NUREG-1421, when considered individually, most of the alternatives analyzed for reducing the risk associated with this issue would be cost-effective in meeting the $1000/person-rem guideline. The objective of the GI-130 resolution is that the risk from the loss of the ESWS be reduced consistent with the two basic requirements of the backfit rule that the corrective alternatives be both substantial and cost-effective.

One of the potential improvements consisting of improvements in TS and emergency procedures was shown to be capable of reducing the CDF as a result of loss of ESW (1.5E-04/RY) by 17 percent (or by approximately 3.0E-05/RY) in a cost-effective manner. As discussed earlier, this is deemed to be consistent with the provisions of the backfit rule.

The overall approach to arriving at the proposed resolution considered both the numerical results of the cost-benefit analysis and the spectrum and type of potential improvements available for potential risk reduction for loss-of-service-water sequences. Those alternatives that could reduce the number of occurrences of the LOSW initiators would be desirable from the prevention perspective. Those alternatives that would help to reduce the consequences of a LOSW would be desirable from the mitigation perspective. The improvements in the TS would assist on the prevention side, while the improved procedures would provide a blend of both prevention and mitigation capabilities.

The conclusion of our analysis is that a substantial increase in the protection of the public health and safety will be derived from the improvements in the TS and procedures, which are justified by the favorable cost/benefit ratio. Hence, in view of the safety significance of the recommended resolution of GI-130, the issuance of this generic letter under 10 CFR 50.54(f) is justified. (See also Item b. below.)

b. <u>The Licensee Response Required and the Cost to Develop the Response to the Information Request</u>

All the recipient licensees or applicants of this generic letter would be requested to review the TS and procedures improvements identified as part of our evaluation of GI-130 and to assess the applicability of these improvements to their respective facilities.

We estimate that the cost of reviewing and evaluating the contents of this generic letter and preparing a response will cost no more than $2500 per licensee or applicant. It is expected that this cost may vary from site to site, depending on the degree to which the TS and procedures improvements apply to individual plants. This cost is insignificant compared to the cost-justified improvements (see cost estimates presented in NUREG-1421), which represent a substantial safety improvement.

c. <u>An Anticipated Schedule for the NRC Use of the Information</u>

We expect that the responses to this generic letter would be submitted within the 180-day schedule required by the generic letter, and that NRC staff review of the responses will be completed within 180 days from their receipt.

ENCLOSURE 2

TO

ATTACHMENT 4 TO TXX-92410

NUREG-0797, CPSES SER (through SSER No. 24), April, 1990.

Pages:

SER	9-8, 9-9
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SSER 23	9-1

establish the extent to which heavy load handling operations satisfy the guidelines of NUREG-0612. Further, the staff asked the applicant to identify the changes and modifications that would be required to fully satisfy these guidelines.

Because this effort will extend over some period of time, certain measures that could be readily implemented, such as identifying safe load paths, developing procedures, operator training and crane inspections, and testing and maintenance, were separately identified in Enclosure 2 to the December 22, 1980 generic letter. The staff will require the applicant to implement these interim measures before the final implementation of NUREG-0612 guidelines and before the issuance of Comanche Peak Operating License. The staff will report on the resolution of this matter in a supplement to this report.

The staff finds that the fuel handling system is in conformance with the requirements of GDC 2 and 61 as they relate to protection against natural phenomena and safe fuel handling and to the guidelines of Regulatory Guides 1.13 and 1.29 with respect to overhead crane interlock and maintaining plant safety in a seismic event. Based on the above and subject to the implementation of the interim measures in Enclosure 2 of the December 22, 1980 generic letter, the staff concludes that the fuel handling system is adequate and, therefore, acceptable, subject to resolution of the matter of NUREG-0612 described above.

9.2 Water Systems

9.2.1 Station Service Water System

The station service water system supplies cooling water to the plant from the safe-shutdown impoundment, which is the ultimate heat sink discussed in Section 9.2.5 of this report. The station service water system cools the component cooling water heat exchangers, emergency diesel generators, lube oil coolers for the safety injection and centrifugal charging pumps, and bearing coolers for the containment spray pumps. All of these cooling loads are required for plant shutdown and/or for mitigating the effects of a LOCA; no other cooling loads are serviced by this system. The station service water system can also be used as a backup water supply for the auxiliary feedwater system and the fire protection booster pumps.

The station service water system consists of two separate and independent full-capacity trains for each reactor unit; cross-connections are provided between trains of the same unit for flexibility. Cross-connections between units are isolated by two locked valves in series. Each train has one full-capacity pump which can be supplied from a separate emergency diesel bus. One train is in operation at all times during normal operation to supply cooling for one train of the essential heat loads indicated above. If the operating station service water pump trips, the other pump automatically starts and is operative within 60 sec to cool the redundant train of essential equipment. During normal unit cooldown and the post-LOCA recirculation phase both trains are normally used although only one train need be operative. During the post-LOCA injection phase, only one station service water system train is used. Adequate isolation from nonessential systems is provided by normally shut Quality Group C, seismic Category I valves. The design of the station service water system ensures that system function is not lost assuming a single active component failure coincident with loss of offsite power. Thus, the requirements of GDC 5 and 44 are met.

The station service water system is designed to Quality Group C and seismic Category I requirements. Connections to other nonessential systems are isolated by Quality Group C seismic Category I valves that are normally shut. The valves to the fire protection system are locked closed. Components of the system are located in seismic Category I structures, which provide protection against tornadoes, tornado-generated missiles, and flooding (see Sections 3.4.1 and 3.5.2 of this SER). Station service water system piping between the pumphouse and the auxiliary building and between the auxiliary building and the safe-shutdown impoundment is seismic Category I and is buried to protect the piping from tornado missiles. Pump motors, valve operators, and controls are located above the postulated level of the probable maximum flood in the seismic Category I pumphouse, which also provides tornado and tornado-missile protection for system components. Thus, the requirements of GDC 2 and the guidelines of Regulatory Guides 1.26, 1.29, 1.102, and 1.117 are met.

The station service water system is separated from the effects of internally generated missiles and high- and moderate-energy pipe breaks (refer to Sections 3.5.1.1 and 3.6.1 of this SER). Pumps and pump motors inside the pumphouse are physically separated from each other by walls designed to preclude coincident damage to redundant equipment from pipe rupture, equipment failure, and missile generation. Thus, the requirements of GDC 4 and the guidelines of BTP ASB 3-1 are met.

The station service water system operates during normal operation; therefore, it does not require additional periodic tests and inspection of the system safety functions. However, the components in operation are interchanged periodically to enable testing and inspection. Recirculation loops are provided around the pumps for testing of these components. Valves, controls, and instrumentation are also tested at regular intervals. The performance of the heat exchangers is monitored periodically to detect excessive scale formation. The system is located in accessible areas to permit inservice inspection as required. Thus, the requirements of GDC 45 and 46 are met.

Based on its review, the staff concludes that the station service water system meets (1) the requirements of GDC 2, 4, 5, 44, 45, and 46 with respect to protection against natural phenomena, missiles, and environmental effects; sharing of essential systems; decay heat removal capability; inservice inspection and functional testing; and (2) the guidelines of Regulatory Guides 1.26, 1.29, 1.102, and 1.117 and BTP ASB 3-1 with respect to the systems quality group and seismic classification and protection against flood, tornado-missile, and pipe break effect. Therefore, it is acceptable.

9.2.2 Reactor Auxiliaries Cooling Water System (Component Cooling Water System)

The component cooling water system (CCWS) provides cooling water to various plant components and rejects the heat to the station service water system (refer to Section 9.2.1 of this SER). The CCWS is an intermediate cooling loop between radioactive or potentially radioactive heat sources and the ultimate heat sink water. The CCWS provides cooling to the following essential plant auxiliary components during all modes of operation including postulated accidents (they are required for safe shutdown and accident mitigation): containment spray pump heat exchangers, residual heat removal (RHR) pump seal coolers, safety-chilled-water system condensers, and control room air conditioning condensers.

to seismic Category I. Because this classification change results in a more conservative design, the change is acceptable and the conclusions reached in the SER remain valid.

Also in the SER, the staff stated that both reactors would not be refueled at the same time, and further, that this was the basis for concluding that the fuel handling system met the requirements of General Design Criterion (GDC) 5 (Appendix A to 10 CFR Part 50) with respect to sharing. Although it is not likely that simultaneous refuelings would be undertaken, it is not expressly forbidden. The actual basis for concluding that the shared portions of the fuel handling system meet the requirements of GDC 5 is that the consequences of a fuel handling system failure in a shared portion of the system does not result in more severe consequences than if the system were not shared. Because the shared portions of the fuel handling system are physically only capable of handling a specified load at any given time, the sharing has no adverse effects on fuel handling accidents. Therefore, the requirements of GDC 5 are met.

The staff indicated in the SER that the spent fuel handling tool and the entire fuel transfer system were designed to seismic Category I requirements. Actually, the spent fuel handling tool is not designed to seismic Category I requirements and is not required to be. Also, only portions of the fuel transfer system necessary for system and containment integrity are designed and required to be designed to seismic Category I requirements. These portions include the fuel transfer tube and flange, refueling gates, and fuel transfer tube expansion joints. This clarification does not alter the staff's conclusions in the SER, and the fuel handling system is still in conformance with the requirements of GDC 2 as they relate to protection against natural phenomena.

9.2 Water Systems

9.2.1 Station Service Water System

In the SER, the staff indicated that the station service water system could be used as a backup water supply for the fire protection booster pumps and that the valves to the fire protection system are locked closed. In FSAR Amendment 66, the applicant identified a design change which eliminated the fire protection booster pumps so that the service water system no longer acts as a backup water supply to the fire protection system. Because the staff's original conclusions were not based on the capability of the station service water system to supply the fire protection system, this design change does not affect the staff's conclusions in the SER, and the service water system remains acceptable.

In FSAR Amendment 66, the applicant indicated that to minimize corrosion due to stagnation in an idle train, both service water pumps would normally be operated to maintain flow in each train. In the SER, the staff stated that during normal plant operation, only one train would be in operation. This is an operational consideration, and either mode of operation is acceptable. Therefore, the staff's conclusions in the SER remain unchanged.

In the SER, the staff indicated that station service water system cross-connections between the two units are isolated by two locked-closed isolation valves in series. In FSAR Amendment 76, the applicant revised the FSAR to clarify that only a single locked-closed isolation valve separates the two units. This is for clarification purposes only, and does not alter the staff's conclusions in the SER, particularly with respect to GDC 5.

9 AUXILIARY SYSTEMS

9.2 Water Systems

9.2.1 Station Service Water Systems

In Safety Evaluation Report (SER) Section 9.2.1, the staff stated that the recirculation loops around the station service water pumps would be used for testing purposes. In Amendment 78 to the Final Safety Analysis Report (FSAR), the applicant identified a design change which includes blind flanges to prohibit flow through these recirulation lines. The reason for the design change was a concern that the plasite coating in the recirculation line could flake off and be returned to the pump suction, possibly causing blockage. The staff concludes that because testing can still be done through the normal flow paths, the requirements of General Design Criterion 46 (10 CFR Part 50, Appendix A) related to cooling water system functional testing are met, and the design change is acceptable.

9.2.2 Reactor Auxiliaries Cooling Water System (Component Cooling Water System)

In Section 9.2.2 of the SER, the staff indicated that the reactor makeup water system provided automatic makeup to the component cooling water surge tank upon receipt of a tank low-low level alarm. In FSAR Amendment 78, the applicant stated that the reactor makeup water system could also be used manually to provide normal makeup to the surge tank. As indicated in the SER, normal makeup can also be provided by the demineralized water system. This manual makeup from the reactor makeup water system provides added flexibility and has been identified here for completeness. This change does not alter the staff's previous conclusions for acceptability in Section 9.2.2 of the SER.

9.2.6 Condensate Storage Facility

In Sections 9.2.6 and 10.4.9 of SSER 22, the staff clarified the usable volume of water reserved in the condensate storage tank for use by the auxiliary feedwater system. It should be noted that the clarification also applies to Section 5.4.3 of the SER which provides a brief discussion of the condensate storage tank volume.

9.3 Process Auxiliaries

9.3.1 Compressed Air System

In SER Section 9.3.1, the staff stated that air accumulators are provided for the auxiliary feedwater flow control valves, steam supply valves to the turbine-driven auxiliary feedwater pump, and the control room air dampers. In FSAR Amendments 66 and 78, the applicant also stated that an air accumulator would be provided for the component cooling water system regulator valve associated with the safeguards chilled water system. This is a matter of clarification to indicate that the valves identified in Section 9.3.1 of the SER are not the

ENCLOSURE 3

TO

ATTACHMENT 4 TO TXX-92410

Generic Letter 89-13 dated July 18, 1989
and
Supplement 1, dated April 4, 1990.

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

July 18, 1989

TO: ALL HOLDERS OF OPERATING LICENSES OR CONSTRUCTION PERMITS FOR NUCLEAR POWER PLANTS

SUBJECT: SERVICE WATER SYSTEM PROBLEMS AFFECTING SAFETY-RELATED EQUIPMENT (GENERIC LETTER 89-13)

Purpose:

Nuclear power plant facilities of licensees and applicants must meet the minimum requirements of the General Design Criteria (GDC) in 10 CFR Part 50, Appendix A. In particular, "GDC 44--Cooling Water" requires provision of a system (here called the service water system) "to transfer heat from structures, systems, and components important to safety to an ultimate heat sink" (UHS). "GDC 45--Inspection of Cooling Water System" requires the system design "to permit appropriate periodic inspection of important components, such as heat exchangers and piping, to assure the integrity and capability of the system." "GDC 46--Testing of Cooling Water System" requires the design "to permit appropriate periodic pressure and functional testing."

In addition, nuclear power plant facilities of licensees and applicants must meet the minimum requirements for quality assurance in 10 CFR Part 50, Appendix B. In particular, Section XI, "Test Control," requires that "a test program shall be established to assure that all testing required to demonstrate that structures, systems, and components will perform satisfactorily in service is identified and performed in accordance with written test procedures which incorporate the requirements and acceptance limits contained in applicable design documents."

Recent operating experience and studies have led the NRC to question the compliance of the service water systems in the nuclear power plants of licensees and applicants with these GDC and quality assurance requirements. Therefore, this Generic Letter is being issued to require licensees and applicants to supply information about their respective service water systems to assure the NRC of such compliance and to confirm that the safety functions of their respective service water systems are being met.

Background:

Bulletin No. 81-03: The NRC staff has been studying the problems associated with service water cooling systems for a number of years. At Arkansas Nuclear One, Unit 2, on September 3, 1980, the licensee shut down the plant when the NRC Resident Inspector discovered that the service water flow rate through the

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containment cooling units did not meet the technical specification requirement. The licensee determined the cause to be extensive flow blockage by Asiatic clams (Corbicula species, a non-native fresh water bivalve mollusk). Prompted by this event and after determining that it represented a generic problem of safety significance, the NRC issued Bulletin No. 81-03, "Flow Blockage of Cooling Water to Safety System Components by Corbicula sp. (Asiatic Clam) and Mytilus sp. (Mussel)."

The bulletin required licensees and applicants to assess macroscopic biological fouling (biofouling) problems at their respective facilities in accordance with specific actions. A careful assessment of responses to the bulletin indicated that existing and potential fouling problems are generally unique to each facility ("Closeout of IE Bulletin 81-03...", NUREG/CR-3054), but that surprisingly, more than half the 129 nuclear generating units active at that time were considered to have a high potential for biofouling. At that time, the activities of licensees and applicants for biofouling detection and control ranged widely and, in many instances, were judged inappropriate to ensure safety system reliability. Too few of the facilities with high potential for biofouling had adopted effective control programs.

Information Notice No. 81-21: After issuance of Bulletin No. 81-03, one event at San Onofre Unit 1 and two events at the Brunswick station indicated that conditions not explicitly discussed in the bulletin can occur and cause loss of direct access to the UHS. These conditions include

1. Flow blockage by debris from shellfish other than Asiatic clams and blue mussels.

2. Flow blockage in heat exchangers causing high pressure drops that can deform baffles and allow flow to bypass heat exchanger tubes.

3. A change in operating conditions, such as a change from power operation to a lengthy outage, that permits a buildup of biofouling organisms.

The NRC issued Information Notice No. 81-21 to describe these events and concerns.

Generic Issue 51: By March 1982, several reports of serious fouling events caused by mud, silt, corrosion products, or aquatic bivalve organisms in open-cycle service water systems had been received. These events led to plant shutdowns, reduced power operation for repairs and modifications, and degraded modes of operation. This situation led the NRC to establish Generic Issue 51, "Improving the Reliability of Open-Cycle Service Water Systems." To resolve this issue, the NRC initiated a research program to compare alternative surveillance and control programs to minimize the effects of fouling on plant safety. Initially, the program was restricted to a study of biofouling, but in 1987 the program was expanded to also address fouling by mud, silt, and corrosion products.

This research program has recently been completed and the results have been published in "Technical Findings Document for Generic Issue 51...," NUREG/CR-5210. The NRC has concluded that the issue will be resolved when licensees and applicants implement either the recommended surveillance and control program described below (Enclosure 1) or its equivalent for the service water system at their respective facilities. Many licensees experiencing service water macroscopic biofouling problems at their plants have found that these techniques will effectively prevent recurrence of such problems. The examination of alternative corrective action programs is documented in "Value/Impact Analysis for Generic Issue 51...," NUREG/CR-5234.

Continuing Problems: Since the advent of Generic Issue 51, a considerable number of events with safety implications for the service water system have been reported. A number of these have been described in information notices, which are listed in "Information Notices Related to Fouling Problems in Service Water Systems" (Enclosure 3). Several events have been reported within the past 2 years: Oconee Licensee Event Report (LER) 50-269/87-04, Rancho Seco LER 50-312/87-36, Catawba LER 50-414/88-12, and Trojan LER 50-344/88-29. In the fall of 1988, the NRC conducted a special announced safety system functional inspection at the Surry station to assess the operational readiness of the service water and recirculation spray systems. A number of regulatory violations were identified (NRC Inspection Reports 50-280/88-32 and 50-281/88-32).

AEOD Case Study: In 1987, the Office for Analysis and Evaluation of Operational Data (AEOD) in the NRC initiated a systematic and comprehensive review and evaluation of service water system failures and degradations at light water reactors from 1980 to early 1987. The results of this AEOD case study are published in "Operating Experience Feedback Report - Service Water System Failures and Degradations," NUREG-1275, Volume 3 (Enclosure 4).

Of 980 operational events involving the service water system reported during this period, 276 were deemed to have potential generic safety significance. A majority (58 percent) of these events with generic significance involved system fouling. The fouling mechanisms included corrosion and erosion (27 percent), biofouling (10 percent), foreign material and debris intrusion (10 percent), sediment deposition (9 percent), and pipe coating failure and calcium carbonate deposition (1 percent).

The second most frequently observed cause of service water system degradations and failures is personnel and procedural errors (17 percent), followed by seismic deficiencies (10 percent), single failures and other design deficiencies (6 percent), flooding (4 percent), and significant equipment failures (4 percent).

During this period, 12 events involved a complete loss of service water system function. Several of the significant causes listed above for system degradation were also contributors to these 12 events involving system failure.

The study identified the following actions as potential NRC requirements.

1. Conduct, on a regular basis, performance testing of all heat exchangers, which are cooled by the service water system and which are needed to perform a safety function, to verify heat exchanger heat transfer capability.

2. Require licensees to verify that their service water systems are not vulnerable to a single failure of an active component.

3. Inspect, on a regular basis, important portions of the piping of the service water system for corrosion, erosion, and biofouling.

4. Reduce human errors in the operation, repair, and maintenance of the service water system.

Recommended Actions To Be Taken by Addressees:

On the basis of the discussion above, the NRC requests that licensees and applicants perform the following or equally effective actions to ensure that their service water systems are in compliance and will be maintained in compliance with 10 CFR Part 50, Appendix A, General Design Criteria 44, 45, and 46 and Appendix B, Section XI. If a licensee or applicant chooses a course of action different from the recommendations below, the licensee or applicant should document and retain in appropriate plant records a justification that the heat removal requirements of the service water system are satisfied by use of the alternative program.

Because the characteristics of the service water system may be unique to each facility, the service water system is defined as the system or systems that transfer heat from safety-related structures, systems, or components to the UHS. If an intermediate system is used between the safety-related items and the system rejecting heat to the UHS, it performs the function of a service water system and is thus included in the scope of this Generic Letter. A closed-cycle system is defined as a part of the service water system that is not subject to significant sources of contamination, one in which water chemistry is controlled, and one in which heat is not directly rejected to a heat sink. If all these conditions are not satisfied, the system is to be considered an open-cycle system in regard to the specific actions required below. (The scope of closed cooling water systems is discussed in the industrial standard "Operation and Maintenance of Nuclear Power Plants," ASME/ANSI OM-1987, Part 2.)

I. For open-cycle service water systems, implement and maintain an ongoing program of surveillance and control techniques to significantly reduce the incidence of flow blockage problems as a result of biofouling. A program acceptable to the NRC is described in "Recommended Program to Resolve Generic Issue 51" (Enclosure 1). It should be noted that Enclosure 1 is provided as guidance for an acceptable program. An equally effective program to preclude biofouling would also be acceptable. Initial activities should be completed before plant startup following the first refueling outage beginning 9 months or more after the date of this letter. All activities should be documented and all relevant documentation should be retained in appropriate plant records.

II. Conduct a test program to verify the heat transfer capability of all safety-related heat exchangers cooled by service water. The total test program should consist of an initial test program and a periodic retest program. Both the initial test program and the periodic retest program should include heat exchangers connected to or cooled by one or more open-cycle systems as defined above. Operating experience and studies indicate that closed-cycle service water systems, such as component cooling water systems, have the potential for significant fouling as a consequence of aging-related in-leakage and erosion or corrosion. The need for testing of closed-cycle system heat exchangers has not been considered necessary because of the assumed high quality of existing chemistry control programs. If the adequacy of these chemistry control programs cannot be confirmed over the total operating history of the plant or if during the conduct of the total testing program any unexplained downward trend in heat exchanger performance is identified that cannot be remedied by maintenance of an open-cycle system, it may be necessary to selectively extend the test program and the routine inspection and maintenance program addressed in Action III, below, to the attached closed-cycle systems.

A program acceptable to the NRC for heat exchanger testing is described in "Program for Testing Heat Transfer Capability" (Enclosure 2). It should be noted that Enclosure 2 is provided as guidance for an acceptable program. An equally effective program to ensure satisfaction of the heat removal requirements of the service water system would also be acceptable.

Testing should be done with necessary and sufficient instrumentation, though the instrumentation need not be permanently installed. The relevant temperatures should be verified to be within design limits. If similar or equivalent tests have not been performed during the past year, the initial tests should be completed before plant startup following the first refueling outage beginning 9 months or more after the date of this letter.

As a part of the initial test program, a licensee or applicant may decide to take corrective action before testing. Tests should be performed for the heat exchangers after the corrective actions are taken to establish baseline data for future monitoring of heat exchanger performance. In the periodic retest program, a licensee or applicant should determine after three tests the best frequency for testing to provide assurance that the equipment will perform the intended safety functions during the intervals between tests. Therefore, in the periodic retest program, to assist that determination, tests should be performed for the heat exchangers before any corrective actions are taken. As in the initial test program, tests should be repeated after any corrective actions are taken to establish baseline data for future monitoring of heat exchanger performance.

An example of an alternative action that would be acceptable to the NRC is frequent regular maintenance of a heat exchanger in lieu of testing for degraded performance of the heat exchanger. This alternative might apply to small heat exchangers, such as lube oil coolers or pump bearing coolers or readily serviceable heat exchangers located in low radiation areas of the facility.

In implementing the continuing program for periodic retesting of safety-related heat exchangers cooled by service water in open-cycle systems, the initial frequency of testing should be at least once each fuel cycle, but after three tests, licensees and applicants should determine the best frequency for testing to provide assurance that the equipment will perform the intended safety functions during the intervals between tests and meet the requirements of GDC 44, 45, and 46. The minimum final testing frequency should be once every 5 years. A summary of the program should be documented, including the schedule for tests, and all relevant documentation should be retained in appropriate plant records.

III. Ensure by establishing a routine inspection and maintenance program for open-cycle service water system piping and components that corrosion, erosion, protective coating failure, silting, and biofouling cannot degrade the performance of the safety-related systems supplied by service water. The maintenance program should have at least the following purposes:

A. To remove excessive accumulations of biofouling agents, corrosion products, and silt;

B. To repair defective protective coatings and corroded service water system piping and components that could adversely affect performance of their intended safety functions.

This program should be established before plant startup following the first refueling outage beginning 9 months after the date of this letter. A description of the program and the results of these maintenance inspections should be documented. All relevant documentation should be retained in appropriate plant records.

IV. Confirm that the service water system will perform its intended function in accordance with the licensing basis for the plant. Reconstitution of the design basis of the system is not intended. This confirmation should include a review of the ability to perform required safety functions in the event of failure of a single active component. To ensure that the as-built system is in accordance with the appropriate licensing basis documentation, this confirmation should include recent (within the past 2 years) system walkdown inspections. This confirmation should be completed before plant startup following the first refueling outage beginning 9 months or more after the date of this letter. Results should be documented and retained in appropriate plant records.

V. Confirm that maintenance practices, operating and emergency procedures, and training that involves the service water system are adequate to ensure that safety-related equipment cooled by the service water system will function as intended and that operators of this equipment will perform effectively. This confirmation should include recent (within the past 2 years) reviews of practices, procedures, and training modules. The intent of this action is to reduce human errors in the operation, repair, and maintenance of the service water system. This confirmation should be completed before plant startup following the first refueling outage beginning 9 months or more after the date of this letter. Results should be documented and retained in appropriate plant records.

Reporting Requirements:

Pursuant to the provisions of Section 182a of the Atomic Energy Act of 1954, as amended, and 10 CFR 50.54(f), each licensee and applicant shall advise the NRC whether it has established programs to implement Recommendations I-V of this Generic Letter or that it has pursued an equally effective alternative course of action. Each addressee's response to this requirement for information shall be made to the NRC within 180 days of receipt of this Generic Letter. Licensees and applicants shall include schedules of plans for implementation of the various actions. The detailed documentation associated with this Generic Letter should be retained in appropriate plant records.

The response shall be submitted to the appropriate regional administrator under oath and affirmation under the provisions of Section 182a, Atomic Energy Act of 1954, as amended and 10 CFR 50.54(f). In addition, the original cover letter and a copy of any attachment shall be transmitted to the U.S. Nuclear Regulatory Commission, Document Control Desk, Washington DC 20555, for reproduction and distribution.

In addition to the 180-day response, each licensee and applicant shall confirm to the NRC that all the recommended actions or their justified alternatives have been implemented within 30 days of such implementation. This response need only be a single response to indicate that all initial tests or activities have been completed and that continuing programs have been established.

This request is covered by the Office of Management and Budget Clearance Number 3150-0011, which expires December 31, 1989. The estimated average burden is 1000 man-hours per addressee response, including assessing the actions to be taken, preparing the necessary plans, and preparing the 180-day response. This estimated average burden pertains only to these identified response-related matters and does not include the time for actual implementation of the recommended actions. Comments on the accuracy of this estimate and suggestions to reduce the burden may be directed to the Office of Management and Budget, Reports Management, Room 3208, New Executive Office Building, Washington, DC 20503 and to the U.S. Nuclear Regulatory Commission, Records and Reports Management Branch, Office of Information and Resources Management, Washington, DC 20555.

Although no specific request or requirement is intended, the following information would be helpful to the NRC in evaluating the cost of this Generic Letter:

1. Addressee time necessary to perform the requested confirmation and any needed follow-up actions.

2. Addressee time necessary to prepare the requested documentation.

If there are any questions regarding this letter, please contact the regional administrator of the appropriate NRC regional office or your project manager in this office.

Sincerely,

James G. Partlow
Associate Director for Projects
Office of Nuclear Reactor Regulation

Enclosures:
1. "Recommended Program to Resolve Generic Issue 51"
2. "Program for Testing Heat Transfer Capability"
3. "Information Notices Related to Fouling Problems in Service Water Systems"
4. "Operating Experience Feedback Report - Service Water System Failures and Degradations in Light Water Reactors," NUREG-1275, Volume 3
5. List of Most Recently Issued Generic Letters

Enclosure 1

RECOMMENDED PROGRAM
TO RESOLVE GENERIC ISSUE 51

This enclosure describes a program acceptable to the NRC for meeting the objectives of the requested Action I in the proposed generic letter. Both Action I and this enclosure are based upon the recommendations described in "Technical Findings Document for Generic Issue 51: Improving the Reliability of Open-Cycle Service-Water Systems," NUREG/CR-5210, August 1988, and "Value/Impact Analysis for Generic Issue 51: Improving the Reliability of Open-Cycle Service-Water Systems," NUREG/CR-5234, February 1989. The NRC has concluded that Generic Issue 51 will be resolved when licensees and applicants implement either the recommended surveillance and control program addressed in this enclosure or an equally effective alternative course of action to satisfy the heat removal requirements of the service water system.

Water Source Type	Surveillance Techniques	Control Techniques
Marine or Estuarine (brackish) or Freshwater with clams	A	B and C
Freshwater without clams	A and D	B and C

A. The intake structure should be visually inspected, once per refueling cycle, for macroscopic biological fouling organisms (for example, blue mussels at marine plants, American oysters at estuarine plants, and Asiatic clams at freshwater plants), sediment, and corrosion. Inspections should be performed either by scuba divers or by dewatering the intake structure or by other comparable methods. Any fouling accumulations should be removed.

B. The service water system should be continuously (for example, during spawning) chlorinated (or equally effectively treated with another biocide) whenever the potential for a macroscopic biological fouling species exists (for example, blue mussels at marine plants, American oysters at estuarine plants, and Asiatic clams at freshwater plants). Chlorination or equally effective treatment is included for freshwater plants without clams because it can help prevent microbiologically influenced corrosion. However, the chlorination (or equally effective) treatment need not be as stringent for plants where the potential for macroscopic biological fouling species does not exist compared to those plants where it does. Precautions should be taken to obey Federal, State, and local environmental regulations regarding the use of biocides.

C. Redundant and infrequently used cooling loops should be flushed and flow tested periodically at the maximum design flow to ensure that they are not fouled or clogged. Other components in the service water system should be tested on a regular schedule to ensure that they are not fouled or clogged. Service water cooling loops should be filled with chlorinated or equivalently treated water before layup. Systems that use raw service water as a source, such as some fire protection systems, should also be chlorinated or equally effectively treated before layup to help prevent microbiologically influenced corrosion. Precautions should be taken to obey Federal, State, and local environmental regulations regarding the use of biocides.

D. Samples of water and substrate should be collected annually to determine if Asiatic clams have populated the water source. Water and substrate sampling is only necessary at freshwater plants that have not previously detected the presence of Asiatic clams in their source water bodies. If Asiatic clams are detected, utilities may discontinue this sampling activity if desired, and the chlorination (or equally effective) treatment program should be modified to be in agreement with paragraph B, above.

PROGRAM FOR TESTING HEAT TRANSFER CAPABILITY

This enclosure describes a program acceptable to the NRC for meeting the objectives of the requested Action II in the proposed generic letter. Both Action II and this enclosure are based in part on "Operating Experience Feedback Report - Service Water System Failures and Degradations," NUREG-1275, Volume 3, November 1988 and "Technical Findings Document for Generic Issue 51: Improving the Reliability of Open Cycle Service Water Systems," NUREG/CR-5210, August 1988. This enclosure reflects continuing operational problems, inspection reports, and industry standards ("Operation and Maintenance of Nuclear Power Plants," ASME/ANSI OM-1987, Part 2.) The NRC requests licensees and applicants to implement either the steps addressed in this enclosure or an equally effective alternative course of action to satisfy the heat removal requirements of the service water system.

Both the initial test program and the periodic retest program should include all safety-related heat exchangers connected to or cooled by one or more open-cycle service water systems. A closed-cycle system is defined as a part of the service water system that is not subject to significant sources of contamination, one in which water chemistry is controlled, and one in which heat is not directly rejected to a heat sink. (The scope of closed cooling water systems is discussed in the industrial standard, "Operation and Maintenance of Nuclear Power Plants," ASME/ANSI OM-1987, Part 2.) If during the conduct of the total testing program any unexplained downward trend in heat exchanger performance is identified that cannot be remedied by maintenance of an open-cycle system, it may be necessary to selectively extend the test program to the attached closed-cycle system.

Testing should be done with necessary and sufficient instrumentation, though the instrumentation need not be permanently installed.

As a part of the initial test program, a licensee or applicant may decide to take corrective action before testing. Tests should be performed for the heat exchangers after the corrective actions are taken to establish baseline data for future monitoring of heat exchanger performance. In the periodic retest program, a licensee or applicant should determine after three tests the best frequency for testing to provide assurance that the equipment will perform the intended safety functions during the intervals between tests. Therefore, in the periodic retest program, to assist that determination, tests should be performed for the heat exchangers before any corrective actions are taken. As in the initial test program, tests should be repeated after any corrective actions are taken to establish baseline data for future monitoring of heat exchanger performance.

An example of an alternative action that would be acceptable to the NRC is frequent regular maintenance of a heat exchanger in lieu of testing for degraded performance of the heat exchanger. This alternative might apply to small heat exchangers, such as lube oil coolers or pump bearing coolers or readily serviceable heat exchangers located in low radiation areas of the facility.

In implementing the continuing program for periodic retesting of safety-related heat exchangers cooled by service water in open-cycle systems, the initial frequency of testing should be at least once each fuel cycle, but after three tests, licensees and applicants should determine the best frequency for testing to provide assurance that the equipment will perform the intended safety functions during the intervals between tests and meet the requirements of GDC 44, 45, and 46. The minimum final testing frequency should be once every 5 years.

I. For all heat exchangers

Monitor and record cooling water flow and inlet and outlet temperatures for all affected heat exchangers during the modes of operation in which cooling water is flowing through the heat exchanger. For each measurement, verify that the cooling water temperatures and flows are within design limits for the conditions of the measurement. The test results from periodic testing should be trended to ensure that flow blockage or excessive fouling accumulation does not exist.

II. In addition to the considerations for all heat exchangers in Item I, for water-to-water heat exchangers

A. Perform functional testing with the heat exchanger operating, if practical, at its design heat removal rate to verify its capabilities. Temperature and flow compensation should be made in the calculations to adjust the results to the design conditions. Trend the results, as explained above, to monitor degradation. An example of this type of heat exchanger would be that used to cool a diesel generator. Engine jacket water flow and temperature and service water flow and temperature could be monitored and trended during the diesel generator surveillance testing.

B. If it is not practical to test the heat exchanger at the design heat removal rate, then trend test results for the heat exchanger efficiency or the overall heat transfer coefficient. Verify that heat removal would be adequate for the system operating with the most limiting combination of flow and temperature.

III. In addition to the considerations for all heat exchangers in Item I, for air-to-water heat exchangers

A. Perform efficiency testing (for example, in conjunction with surveillance testing) with the heat exchanger operating under the maximum heat load that can be obtained practically. Test results should be corrected for the off-design conditions. Design heat removal capacity should be verified. Results should be trended, as explained above, to identify any degraded equipment.

B. If it is not possible to test the heat exchanger to provide statistically significant results (for example, if error in the measurement exceeds the value of the parameter being measured), then

1. Trend test results for both the air and water flow rates in the heat exchanger.

2. Perform visual inspections, where possible, of both the air and water sides of the heat exchanger to ensure cleanliness of the heat exchanger.

IV. In addition to the considerations for all heat exchangers in Item I, for types of heat exchangers other than water-to-water or air-to-water heat exchangers (for example, penetration coolers, oil coolers, and motor coolers)

A. If plant conditions allow testing at design heat removal conditions, verify that the heat exchanger performs its intended functions. Trend the test results, as explained above, to monitor degradation.

B. If testing at design conditions is not possible, then provide for extrapolation of test data to design conditions. The heat exchanger efficiency or the overall heat transfer coefficient of the heat exchanger should be determined whenever possible. Where possible, provide for periodic visual inspection of the heat exchanger. Visual inspection of a heat exchanger that is an integral part of a larger component can be performed during the regularly scheduled disassembly of the larger component. For example, a motor cooler can be visually inspected when the motor disassembly and inspection are scheduled.

INFORMATION NOTICES RELATED TO FOULING PROBLEMS IN SERVICE WATER SYSTEMS

1. Information Notice No. 83-46: "Common-Mode Valve Failures Degrade Surry's Recirculation Spray Subsystem," July 11, 1983

2. Information Notice No. 85-24: "Failures of Protective Coatings in Pipes and Heat Exchangers," March 26, 1985

3. Information Notice No. 85-30: "Microbiologically Induced Corrosion of Containment Service Water System," April 19, 1985

4. Information Notice No. 86-96: "Heat Exchanger Fouling Can Cause Inadequate Operability of Service Water Systems," November 20, 1986

5. Information Notice No. 87-06: "Loss of Suction to Low Pressure Service Water System Pumps Resulting from Loss of Siphon," January 30, 1987

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

April 4, 1990

J. CAHILL

TO: ALL HOLDERS OF OPERATING LICENSES OR CONSTRUCTION PERMITS FOR NUCLEAR POWER PLANTS

SUBJECT: SERVICE WATER SYSTEM PROBLEMS AFFECTING SAFETY-RELATED EQUIPMENT (GENERIC LETTER 89-13, SUPPLEMENT 1)

On July 18, 1989, the U.S. Nuclear Regulatory Commission (NRC) issued Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment." On October 23, 1989, the NRC announced in the Federal Register that it would hold four workshops on this generic letter. The NRC conducted these workshops in Philadelphia, Atlanta, Chicago, and Denver on November 28 and 30 and December 5 and 7, 1989, respectively. The NRC answered written questions submitted through appropriate project managers in the Office of Nuclear Reactor Regulation before the first workshop and questions submitted at each workshop. Transcripts of these meetings are available in the NRC Public Document Room, 2120 L Street NW, Washington, DC.

This supplement contains the questions and answers read into the transcripts during the workshops, except for the following changes. Questions received in the general, Action I, and Action II categories have been grouped according to topic. In addition, the NRC staff modified some answers after the workshops with the aim of furnishing additional guidance. Please contact the project manager if you have questions on this matter.

Sincerely,

James G. Partlow
Associate Director for Projects
Office of Nuclear Reactor Regulation

Enclosures:
1. Questions and Answers
2. List of Recently Issued NRC Generic Letters

Technical Contact: C. Vernon Hodge, NRR
(301) 492-1169

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Enclosure 1

QUESTIONS AND ANSWERS

I. GENERAL

A. Reporting Requirements

1. If we are looking into several options to determine which one is the most beneficial, however, [if] we have not made a decision by the date that our response is due, would it be acceptable to explain this and confirm that whatever option is chosen will be completed on time? (Wisconsin Public Service)

Answer

Yes. The purpose of the 180-day response was to obtain the commitments, plans, and schedules of licensees and applicants to implement the recommended actions of the generic letter (GL) or their equally effective alternatives. The licensee's or applicant's decision-making process should be made a part of the plans and schedules and submitted to the NRC when the response is due. If other circumstances prevent such submittal, such as the regulatory requirements of the technical specifications or outside government agencies, the licensee or applicant should arrange any adjustments of the schedule with the appropriate Office of Nuclear Reactor Regulation (NRR) project manager.

2. What was the basis (experience) used to determine the schedule of completion for Items 2 and 4? Do these schedules consider utilities with more than one plant? (Northeast Utilities)

Answer

The basis for the schedule was an appearance of reasonableness. The schedules given apply to single units. Schedules are intended to be flexible and should be reported to the staff in the licensee's or applicant's response with justification if the recommended schedule in Generic Letter 89-13 is not used. The licensee or applicant should arrange any adjustments of the schedule with the appropriate NRR project manager.

3. If the CCWS [component cooling water system] is part of the scope for Items IV, V of the generic letter, would it be possible to modify the completion date commitments to fit this into our already existing SSFI [safety system functional inspection] schedule? (Wisconsin Public Service)

Answer

Yes. See the answer to Question I.A.1. Also, this request appears to be reasonable for good cause. The licensee or applicant should arrange any adjustments of the schedule with the appropriate NRR project manager.

4. Can we defer the Unit 2 required action dates so that they coincide with those of Unit 1 (i.e., October 1990 to April 1991 for Unit 2)? (Houston Lighting and Power)

Answer

Yes, with appropriate justification and arrangement with the appropriate project manager.

5. For Action Items 4 and 5 of the GL 89-13, HL&P [Houston Lighting and Power] plans to utilize the information gathered from a safety system functional inspection (SSFI) for the essential cooling water (ECW) and component cooling water (CCW) systems.

   The SSFI for the ECW system supports the GL 89-13 reporting requirements; however, the CCW SSFI is scheduled for 1990. Is it acceptable to separate the reporting for the ECW and CCW systems, that is, extend the CCW portion of GL 89-13? (Houston Lighting and Power)

   Answer

   Yes. See the answers to Questions I.A.1 and I.A.3.

6. The SSFI method currently being used to satisfy Recommended Actions IV and V is manhour intensive. Can program deficiencies identified in the open-loop system be applied horizontally to the closed-loop systems in lieu of an additional SSFI? (Houston Lighting and Power)

   Answer

   Yes. A licensee or applicant may extend identified deficiencies, based on other actions already taken (such as an SSFI) on the open-loop system, to the closed-loop system, provided the licensee or applicant confirms that existing configuration control programs have been applied to the closed-loop system.

B. Backfit

1. The actions proposed by GL 89-13 constitute new staff positions. To perform the testing and inspection requested by the GL, it may well be necessary for licensees to make significant plant modifications. For example, licensees will likely be forced to install new instrumentation in order to perform tests and to monitor test results. Furthermore, changes will be required of procedures. An additional requirement of a walkdown has been made. The proposed tests may be beyond the licensing basis of the plant. These requirements seem to fit the definition of a backfit under 10 CFR 50.109(a)(1). Therefore, why were the requirements in the GL promulgated under the provisions of Section 50.54(f)? (Nuclear Utility Backfitting and Reform Group [NUBARG])

Answer

The NRC concluded that it was not assured that licensees and applicants are in compliance with existing regulations, namely General Design Criteria 44, 45, and 46 of Appendix A of 10 CFR Part 50 and Appendix B of that part. The recommended actions in this generic letter do represent new staff positions and are considered a backfit in accordance with NRC procedures. This backfit is to bring facilities into compliance with existing requirements. The regulatory request for information under 10 CFR 50.54(f) represented by the generic letter is designed to gain this assurance.

2. Was a backfit analysis of the testing and inspection requirements performed? Will the staff make that analysis available to the public? In particular, did the staff's backfitting analysis, if any, justify the need for actions on closed systems? (NUBARG)

Answer

The staff performed an analysis for review by the NRC Committee to Review Generic Requirements (CRGR). Because the CRGR reviews all proposed bulletins and generic letters, among other proposed staff actions, this may properly be referred to as a regulatory analysis pursuant to 10 CFR 50.54(f). The CRGR analysis is available in the NRC public document room (Accession No. 8907180077).

Indeed, the staff was not able to justify inclusion of closed systems in the recommended actions of the generic letter, as it had once proposed to do. Accordingly, the generic letter was issued without the requirement for reporting heat transfer capability of closed-cycle heat exchangers.

C. Inspections

1. What level of detail should be included in the descriptions of existing and proposed programs? (Philadelphia Electric)

Answer

The level of detail retained in plant records should be sufficient to demonstrate that the heat removal requirements of the service water system are satisfied. Each recommended action delineated in the generic letter or equivalent should be addressed in sufficient detail to demonstrate the licensee's evaluation of the action. It should be noted that this information should be available in appropriate plant records but need not be submitted to the NRC.

2. Generic Letter 89-13 provides the licensee with a great deal of leeway in defining their programs. This leeway is desirable and justifiable given the wide variation in conditions that may prevail. It is anticipated that the main mechanism for judging compliance with the generic letter will be NRC site inspections. During such inspections, what will be the basis for judging the acceptability of the program? What is being done to promote consistency in interpretations among regions? (Duke Power)

Answer

The engineering judgment of the inspector, based on the addressee's documentation for the program, will be relied upon to determine acceptability of the program. The purpose of the generic letter is for licensees and applicants to assure that the heat removal requirements for the service water system are satisfied. This is required by regulations, particularly General Design Criteria 44, 45, and 46 of Appendix A of 10 CFR Part 50 and Appendix B of that part.

The workshops constitute to date the NRC effort to promote consistency among the regions regarding Generic Letter 89-13. The NRC will issue the questions and answers submitted before and during the workshops as a supplement to Generic Letter 89-13 within the next two months. The traditional method of issuing a temporary instruction for inspection from headquarters to regional offices will not be used for this generic letter. At this time, only audits of implementation of Generic Letter 89-13 are planned rather than systematic inspections. If an event or problem related to the service water system occurs at a particular plant, that plant's actions in response to Generic Letter 89-13 will be reviewed to determine if inadequacies in the implementation of the Generic Letter contributed to the event or problem. The supplement to Generic Letter 89-13 will also reference the transcripts for these workshops, which will be placed in the NRC public document room. Authors of the generic letter will be available by telephone to licensees, applicants, and inspectors to address questions on implementation of the Generic Letter.

3. Many of your responses this morning (Workshop II in Atlanta on November 30, 1989) fall back to the standard NRC position that the licensee should provide adequate assurance that they have a program or actions in place to satisfy the generic letter concerns. This position could create a problem later when the inspector shows up to review our program. What kind of guidance will the NRR and RES [Office of Nuclear Regulatory Research] staff be providing to the inspector? If you don't provide specific instruction in something like a TI [temporary instruction], the acceptability of a given program will be left to the opinion of an individual inspector. When will this type of guidance be available? (Florida Power)

   Answer

   Both the kind of guidance and the schedule are discussed in the answer to the previous question, C.2.

4. When does the NRC envision inspections to begin on this letter? (Florida Power)

   Answer

   At this time, only audits of implementation of Generic Letter 89-13 are planned rather than systematic inspections. The schedules for such audits have not been determined at this time.

D. Miscellaneous

1. Similar regional meetings regarding Generic Letter 89-04 were conducted in the June 1989 time frame. To date, the minutes from these meetings have not been received. When can we expect the minutes from the Generic Letter 89-13 meetings? (Duke Power)

   Answer

   Concerning Generic Letter 89-04, the minutes were issued by letter dated October 25, 1989, signed by James Partlow, Associate Director for Projects, Office of Nuclear Reactor Regulation. The minutes are being distributed to all licensees and applicants, meeting attendees, NRR project managers, and the NRC public document room.

   Concerning Generic Letter 89-13, see the answer to Question I.C.2. To repeat, the NRC will issue the questions and answers submitted before and during the workshops as a supplement to Generic Letter 89-13 within the next two months. The supplement to Generic Letter 89-13 will also reference the transcripts for these workshops, which will be placed in the NRC public document room.

2. Do Recommended Actions IV and V apply to closed cooling systems? (Kansas Gas and Electric)

   Answer

   Yes. The generic letter defines service water systems as including both open-cycle portions and intermediate closed-cycle loops that function to remove heat from safety-related structures, systems, or components to the ultimate heat sink. Recommended Actions I, II, and III specifically apply to open-cycle portions of the service water system. Recommended Action II can be extended to the closed-cycle portions as conditions warrant. Whether a cooling loop is open or closed is not specified for Actions IV and V.

II. ACTION I - BIOFOULING

A. Terms

1. What is the definition of layup? (Philadelphia Electric)

   Answer

   Layup is the treatment of a system that is isolated or in a standby condition under stagnant flow conditions to prevent corrosion. Refer to "Plant Layup and Equipment Preservation Sourcebook," EPRI NP-5106 (March 1987). Those service water cooling loops normally operated with water in the system, even in a standby condition, should contain chlorinated or equivalently treated water rather than untreated water.

2. What constitutes an infrequently used component? (Philadelphia Electric)

   Answer

   Paragraph C in Enclosure 1 in the generic letter states that redundant and infrequently used cooling loops should be flushed and flow tested periodically at the maximum design flow to ensure that they are not fouled or clogged. This recommended action refers to emergency core cooling system loops or other safety-related cooling loops that are normally in the standby condition. The next sentence states that other components in the service water system should be tested on a regular schedule to ensure that they are not fouled or clogged. This recommended action refers to pumps, pipes, valves, strainers, or other components even in loops in which water is normally flowing. Often inadequate flow may exist in these loops and not be detected without such testing.

   Consider a system in which water is normally flowing that has parallel branches in which the states of the components in the branches are not often changed. For example, branch throttle valves initially set before the plant began operation may not be controlled by procedure. Subsequent changes in the throttle valve positions for various reasons or clogging of them or other components in the branches would upset the initial system flow balance without detection.

3. Redundant and infrequently used cooling loops: (Unidentified)

   a. Define infrequently used.

      Answer

      The wording "infrequently used cooling loops" is intended to apply to those normally in a standby mode under stagnant flow conditions. The Generic Letter 89-13 program should address means for ensuring that fouling does not occur under such conditions.

   b. If performance testing is done on all heat exchangers periodically, will this satisfy the intent of the recommendation?

Answer

Yes. Periodic performance monitoring of all safety-related heat exchangers is acceptable, provided it ensures heat transfer capability, not merely flow or pressure drop.

4. Recommendation I of Generic Letter 89-13 states that "initial activities should be completed before plant startup following the first refueling outage beginning nine months or more after the date of this letter." What is the intent of the phrase, "initial activities"? Does it mean:

The first "round" of activities (inspections, flushes, biocide treatment, etc.) has been completed; or,

The mechanisms have been put in place which will culminate in the implementation of the program (biocide discharge permits submitted, procedures written and approved)? (Duke Power)

Answer

Both these possibilities could be included in the intent of the phrase. For those activities involving an outside governmental agency, the licensee or applicant should arrange a needed adjustment in the schedule with the appropriate NRR project manager. For those activities involving procedural changes or new procedures, "initial activities" refers to those inspections or other activities by which the need for procedural changes or new procedures is identified.

B. Inspection of Intake Structure

1. When determining whether a plant has clams in its source water, does consideration need to be given to the presence of clams in the plant vicinity (local environment) or solely in the water body (source of cooling water)? (Philadelphia Electric)

Answer

The purpose of this recommended action is to enable a licensee or applicant to know if the service water system might be subject to biofouling. All potential sources of water for the service water system should be examined annually for the presence of biofouling species. If no waters in the local environment of a plant can get inside piping and components to cause biofouling degradation of the heat transfer function of the service water system, then such waters do not need to be sampled.

2. Enclosure 1 to Generic Letter 89-13 recommends varying requirements for service water systems based on intake structure configuration and location. In a service water system in which the suction point of the service water pumps is in the collecting basin for the ultimate heat sink (cooling tower) would the basin be considered the intake structure or would the source of basin makeup water be considered the intake structure? (Mississippi Power and Light)

Answer

Each licensee or applicant should define the scope of the intake structure. The NRC considers that an intake structure would contain all the waters eventually used in the system. See the answer to Question II.B.1.

3. Does the visual inspection of the intake structure apply to the intake piping as well? If so, will NRC give guidance as to replacement criteria of piping? If not, is [American National Standards Institute Standard] B31.1 for wall thinning the appropriate criteria? (Wisconsin Public Service)

Answer

Visual inspection of the intake structure may apply to the intake piping. The minimum wall thickness is defined by the code of record that was used to design the piping system. Before 1971, ANSI B31.1 was applicable. Since 1971, ASME Code Section 3 applies to piping design and fabrication.

4. When stating we should be aware of other plants (refer to Philadelphia workshop transcript, p. 21), facilities, etc., that use the same service water source (e.g., river) and their biofouling problems, how far does that extend? Within 5 miles? 50 miles? Please clarify. (Unidentified)

Answer

The NRC cannot place a quantitative range on biofouling awareness. Conditions at each site would determine an appropriate program or how far away to monitor for biofouling. The licensee or applicant should use the best available site-specific information and establish an appropriate monitoring program.

5. Refer to Action Item I in Gen. Ltr 89-13. If the current sampling program, which was initiated to detect Asiatic clams, has not found any mollusk infestation do the sampling methods need to be modified to detect Zebra mussels? (Niagara Mohawk Power)

Answer

The recommended sampling methods in Recommended Action I are intended to be general enough to enable licensees and applicants to become aware of macrobiofouling agents early enough to prevent the associated fouling problem from adversely affecting the safety-related function of the service water system. See Information Notice 89-76, "Biofouling Agent: Zebra Mussel."

6. Inspection of intake structure each refuel cycle. Could inspection of other intake structures (fossil units) on the same body of water that have been in place and in service for up to 40 years be used to justify either to extend the frequency of inspection or maybe no inspection at all? (Unidentified)

Answer

The inspection of the intake structure should not be restricted to potential macroinvertebrate fouling. If the program in place at the fossil unit mentioned has been shown to be effective to date for detecting of fouling, including biofouling, mud, and silt, then it may be sufficient for future monitoring. However, the licensee or applicant should be aware of and should consider possible rapid changes in environmental conditions and ensure that its program includes the best available site-specific information.

7. If it can be shown that the introduction of mollusks into the service water system is not plausible based on service water system design and makeup water system design, can the requirements of Generic Letter 89-13 concerning both inspection for and control of mollusks be waived? (Mississippi Power and Light)

Answer

The purpose of the generic letter is for licensees and applicants to assure that the heat removal requirements for the service water system are satisfied. If this can be done by the proposed program, then it is acceptable.

8. If yearly inspection of a plant's service water intake structure shows no indication of Asiatic clams, and testing results indicate that corrosion is not microbiologically influenced, is it acceptable to continue with the annual inspections for clams and perform maintenance and testing as required in Actions II and III of GL 89-13, in lieu of a chlorination injection program? (Commonwealth Edison)

   Answer

   This appears to be reasonable for good cause shown. See the answers to the previous two questions.

9. Larva sampling is difficult to do. We already have a sampling commitment, but we don't want to do this and can justify not doing it. (Kansas Gas and Electric)

   Answer

   An equally effective course of action with justification is acceptable. However, the earlier that a licensee or applicant can identify the presence of a biofouling species in a source body of water for the service water system, the better chance it will have to control the situation and prevent a potential safety problem.

10. Does the generic letter imply that biofouling monitoring methods are required? Are sidestream or inline monitoring methods necessary? Does the NRC have a preference concerning the methods of visual, UT [ultrasonic testing], radiography, or electrochemical (Corrator) probes to monitor for biofouling? (South Carolina Electric and Gas)

    Answer

    Biofouling monitoring of the source water would generally be necessary. Licensees and applicants may use, however, equally effective programs for Recommended Action I. Sidestream or inline monitoring is effective and could be used for this purpose. The NRC has no preference concerning methods for biofouling monitoring or nondestructive service water system examination provided the selected method is effective.

11. For NTOL [near-term operating license] plants, when does GL 89-13 have to be implemented? (Unidentified)

    Answer

    As stated in Generic Letter 89-13, both licensees and applicants should observe the same schedule. The licensee or applicant should arrange any justified adjustments of the schedule with the appropriate NRR project manager.

12. On Item C, Enclosure 1, since macroscopic biological fouling and MIC [microbiologically influenced corrosion] have not been problems at CNS [Cooper Nuclear Station], does that exempt us from the recommendation for chlorinating systems using raw water before layup? (Nebraska Public Power District)

Answer

Yes, if appropriate justification is provided.

13. Is periodic maintenance adequate to address layup without chlorination? (Nebraska Public Power District)

Answer

Yes, if appropriate justification is provided.

14. On Item D, Enclosure 1, in lieu of taking annual water samples to determine if Asiatic clams have populated the water source, could we perform annual visual inspections of sample heat exchangers cooled by river water? (Nebraska Public Power District)

Answer

The purpose of sampling the water source itself was to ensure that means of potential fouling were identified early. However, if the best available site-specific information does not indicate a means of biofouling, then visual examination of a sample of service water system heat exchangers may be sufficient, with proper justification, to detect fouling.

C. Biocide Guidance

1. Enclosure 1 to Generic Letter 89-13 describes an acceptable program, to the NRC, to implement Recommendation No. I of the generic letter. This program includes biocide treatment regardless of whether the plant is susceptible to macroscopic biological fouling or not. Will a program that does not include biocide treatment be acceptable to the NRC? (Duke Power)

Answer

Yes, if good cause is shown. Note the guidance in Paragraph B of Enclosure 1 to Generic Letter 89-13. Chlorination or equally effective treatment is included for freshwater plants without clams because it can help prevent microbiologically influenced corrosion.

2. With regards to Enclosure 1 of the generic letter; (Wisconsin Public Service)

   a. Will NRC give guidance on use of biocides other than chlorine?

   Answer

   No. The NRC is interested in the effective heat transfer of the systems. It is not in a position to consult on the various biocide treatments. Refer to "Plant Layup and Equipment Preservation Sourcebook," EPRI NP-5106 (March 1987).

   b. Do we need to continuously chlorinate, if under our inspection program, we find no evidence of macroscopic fouling? Do WPDES [sic; National Pollutant Discharge Elimination System] discharge limits take precedence to this?

   Answer

   No. The program described in Enclosure 1 represents an acceptable program for implementing Recommended Action I. A licensee or applicant can choose to pursue an equally effective alternative course of action if justified. Precautions should be taken to obey Federal, State, and local environmental regulations regarding the use of biocides. This includes the National Pollutant Discharge Elimination System (NPDES) discharge limits administered by the U.S. Environmental Protection Agency, which were referenced in the question.

   c. Is demineralized water acceptable for use in wet layup of stagnant SW [service water] piping?

Answer

This question must be decided by the licensee or applicant. The result should be that the heat removal requirements for the service water system are satisfied. To accomplish this, the NRC recommends that such piping be flushed and flow tested periodically to ensure that clogging is absent and that chlorinated or equivalently treated water will be used to fill service water loops before layup to help prevent MIC. We note also that industry recommends treatment of service water systems during outages to prevent microbes. See EPRI NP-5106.

3. Some State regulations do not permit the use of biocides above the minimum detectable level, yet Enclosure 1 to the GL appears to require biocides while cautioning plants not to violate State and local regulations. Since it is not possible in some jurisdictions to use any biocides without violating State and local regulations, what alternatives to biocides are acceptable to the staff? (Nuclear Utility Backfit Action Reform Group [NUBARG])

Answer

An alternative course of action is acceptable if the heat removal requirements for the service water system are satisfied. Biocides can be deactivated before discharge. The treated biocides must meet NPDES discharge limits. At least one utility (Trojan) is deactivating the biocides before discharge. See the answers to the previous two questions.

D. Fire Protection Systems

1. To what extent should fire protection systems be addressed in response to the generic letter? (Philadelphia Electric)

Answer

The generic letter is not designed to focus on fire protection systems, which are not safety-related, but to incidentally include them if they use untreated water that could be subject to the service water system problems described in the generic letter.

2. We use well water (raw water) as a source to the fresh water/fire protection storage tanks. Do we need to chlorinate these tanks or do we need to conduct full-flow surveillance tests on all fire protection piping runs? We presently only surveil the fire pumps for flow, not the piping runs. We do not presently chlorinate these tanks. The SW system per se is not used to fill these tanks; separate well pumps are used. (Public Service Electric and Gas)

Answer

The recommended program described in Enclosure 1 of the generic letter was developed under a government-sponsored research program. If a licensee or applicant chooses an alternative course of action from that recommended in Enclosure 1, it should assess the potentials for macroscopic biofouling and microbiologically influenced corrosion (MIC) and justify that the alternative course of action will result in satisfaction of the heat removal requirements for the service water system.

Paragraph B of Enclosure 1 of the generic letter recommends chlorination whenever the potential for a macroscopic biological fouling species exists. Such a potential may not exist for these wells, but the potential for MIC should also be considered.

Paragraph C of Enclosure 1 of the generic letter recommends periodic flow testing of infrequently used loops at the maximum design flow to ensure that they are not fouled or clogged. If the fire protection piping runs are subject to biofouling but the water is not treated to protect against biofouling, then full-flow testing of the runs may be appropriate to ensure that the potential for clogging is minimal. This paragraph also recommends chlorination to help prevent MIC.

3. Do Generic Letter 89-13 requirements apply to the fire protection systems which are not fed by either the service water system or the service water Intake? (South Carolina Electric and Gas)

   Answer

   The generic letter is not designed to focus on fire protection systems, but to incidentally include them if they use untreated water that could be subject to the service water system problems described in the generic letter.

4. What is the basis for requiring treatment of fire protection systems that use raw service water as a source (Enclosure 1, Section C)? (NUBARG)

   Answer

   See the answers to the previous two questions.

5. For a fire protection system supplied by raw water which meets flow requirements and does not provide safety-related cooling, are any actions required? (Iowa Electric Light and Power)

   Answer

   No. See the answer to Question II.D.1.

III. ACTION II - HEAT TRANSFER TESTING

A. Testing Method

1. Should the proposed heat exchanger heat transfer testing method be provided for prior NRC review and approval? (Philadelphia Electric)

   Answer

   No.

2. Has the NRC reviewed the EPRI SWWG [Electric Power Research Institute Service Water Working Group] document prepared by Duke Power and Toledo Edison describing several methods of heat transfer testing? If so, is the temperature effectiveness method acceptable? Which methods are acceptable? (Philadelphia Electric)

   Answer

   The staff has not formally reviewed this document but has received a draft copy. A method of heat transfer testing is acceptable for purposes of satisfying the generic letter if it can assure that the heat removal requirements for the service water system are satisfied.

3. If the pressure drop across a heat exchanger at design flow is less than or equal to the manufacturer's specification, is heat transfer testing required, provided the baffles have been inspected to ensure that the flow is not bypassing the coils? (Philadelphia Electric)

   Answer

   The objective is not to satisfy the manufacturer's specification for flow in a heat exchanger so much as it is to ensure that the heat removal requirements for the service water system are satisfied. If the latter assurance can be achieved by showing design flow to be necessary and sufficient, then heat transfer testing would be superfluous.

4. Page 5, paragraph 3. What is meant by "The relevant temperatures should be verified to be within the design limits?" Does this imply testing should be conducted with the design-basis heat load? Is it acceptable to conduct testing for all heat exchangers at off normal conditions, provided accurate and relevant data can be acquired, and analytical methods used to determine the heat transfer capacity at design conditions? (Portland General Electric)

   Answer

   Enclosure 2 of the generic letter discusses in detail verifying various parameters to be within design limits. Testing with design-basis heat loads is recommended ideally. If testing can be done under design conditions, it should be done under those conditions. Realizing this may not be practicable in nonaccident circumstances, the next best step is to conduct tests under off-design conditions and analytically correct the results to the design conditions. Such a procedure is acceptable if it is necessary but not if testing under design conditions is practicable.

5. For heat exchangers that cannot be tested at the design heat removal rate, what is the NRC-recommended method to extrapolate the test data to design conditions? Does the NRC have any additional recommendations for extrapolating test data taken at very low loads (less than 10% design load) to design conditions? (Southern California Edison)

<u>Answer</u>

The staff does not have a recommended method of extrapolation. However, the EPRI service water system working group has been developing such guidance as have some licensees such as Duke Power. These may be places to start when developing appropriate testing programs.

6. Recommended Action II requires that "the relevant temperatures should be verified to be within design limits." Also, Enclosure 2, Item II.A states, "Perform functional testing with the heat exchanger operating, if practical, at its design heat removal rate to verify its capabilities. Temperature and flow compensation should be made in the calculations to adjust the results to the design conditions."

It is not practical to test the heat exchangers at design heat removal rates. Also, we are unable to find a method which has the requisite level of precision to adjust the test results to design conditions.

Please discuss an acceptable method to adjust the test results to the design conditions. Also provide the scientific bases, or a reference, for the proposed method.

Also, the heat removal test cannot be performed on the containment spray heat exchangers because there is no heat source. The only test that can be performed is a pressure drop test. Is this acceptable? If not, what is recommended? (Indiana and Michigan Power)

<u>Answer</u>

As mentioned previously, the NRC does not have a recommended test method. See the answer to the previous question. With regard to the testing of containment spray heat exchangers, as of all safety-related heat exchangers, a pressure drop test alone is not sufficient to satisfy the indicated heat transfer capability concerns. If it is not practicable to test a heat exchanger, then the licensee or applicant may propose a program of periodic inspection, maintenance, and cleaning as an alternative. We are aware, however, of one licensee who was able to test the containment spray heat exchanger by heating the refueling water storage tank water approximately 10°F and then performing temperature monitoring tests as well as pressure drop tests.

7. To what degree should a utility endeavor to monitor real-time corrosion rates of the service water system? Is trending of heat exchanger performance and visual inspections sufficient documentation of the component's internal condition? (South Carolina Electric and Gas)

Answer

It is not necessary to determine numerical real-time corrosion rates in the service water system. The licensee's or applicant's monitoring program should be sufficient to identify degradation and to take the necessary corrective action before system performance is unacceptably affected. Trending of data is a recommended approach to monitoring system performance.

8. Is the NRC staff stating that a technical evaluation of a heat exchanger's capability to perform its design safety function cannot be used in lieu of initial testing? Therefore, all heat exchangers must be tested and even maintenance/cleaning cannot be used in lieu of initial testing because it would require a technical evaluation to determine maintenance/cleaning frequency. Also, when considering several identical heat exchangers in one loop, do all the heat exchangers require testing or maintenance/cleaning? (Philadelphia Electric)

Answer

No, the initial heat exchanger "test" program may consist of both performance testing of some heat exchangers and maintenance and cleaning of others. The initial test program was intended to ensure that the licensee or applicant has established a baseline for all safety-related heat exchangers served by the service water system and, therefore, is confident that they can perform their heat removal function. As further clarification, if there are several identical heat exchangers in one service water loop, a licensee or applicant may perform testing or develop a maintenance and cleaning program for these heat exchangers based on the most limiting one as part of its initial "test" program. Justification for the basis of comparable service conditions should be included in the evaluation when all identical heat exchangers are not tested.

9. Refer to Action Item II of Gen. Ltr 89-13. Can the test program include data taken during routine operating intervals, with minimum load on heat exchangers, and extrapolated to substantiate adequate HX [heat exchanger] performance? Or when does the NRC consider it impractical to test a HX at the design heat removal rate? (Niagara Mohawk Power)

Answer

Yes, if testing under design conditions is not practicable. See the answers to Questions III.A.4, III.A.5, and III.A.6 above. The licensee or applicant should determine whether such testing is practicable. See the answer to Question III.A.14.

10. In Enclosure 2 of the generic letter, a statement is made that testing should be done with necessary and sufficient instrumentation. Flow measurement is one of the two key parameters when measuring heat exchanger performance. It is also the most difficult since most plants never provided means to measure individual flow rates to service water users. In general, orifice plates, venturi tubes, pitot tubes and flow nozzles are the only recognized traceable type of flow measuring devices, all of which require intrusive elements. To be able to utilize such devices would require plant system modifications at great expense to the utility and its customers. A less expensive alternative to this would be to use non-intrusive, non-traceable devices such as transit-time ultrasonic flow meters which with current technology give very reliable results. Trending of data taken with such devices would appear to be equally effective for detecting degradation in cooling water systems. Would the NRC recognize the value and benefit of using such devices and accept programs which utilize them? (Detroit Edison)

Answer

Yes.

11. Thermographic cameras could potentially be used to scan the tubes on air to water heat exchangers to see temperature profiles of the tubes and detect tube blockage or sediment in the tubes. Will the NRC accept such qualitative checks rather than quantitative measurements to prove that a heat exchanger is not fouled? (Detroit Edison)

Answer

Yes. However, additional means should be included in the program to ensure adequate heat transfer.

12. If off-the-shelf software is reviewed for technical adequacy and subsequently utilized to perform heat exchanger performance calculations, will it be acceptable to the NRC? (Detroit Edison)

Answer

Yes.

13. If a heat exchanger performance test reveals that a heat exchanger is in a degraded condition, the first obvious question will be as to what the impact of the degraded condition is on system operability. Will a heat exchanger performance program be considered the same as the plant's surveillance program with the same ramifications for questioning plant/system operability? If so, is the NRC considering asking the licensees to include limiting condition for operation statements in their technical specifications? (Detroit Edison)

Answer

If a heat exchanger's heat transfer capability is shown to be degraded below levels needed for performance of its safety-related function, it is considered inoperable. The staff does not intend that elements of these programs be included in plant technical specifications.

14. Restate what you would consider acceptable as "impractical conditions for testing." What are "acceptable alternatives," especially for utilities not privy to EPRI information? (Portland General Electric)

Answer

An impractical condition would be a situation where flow or the means of applying a heat load cannot be achieved because of system configuration. An acceptable alternative is a periodic inspection or maintenance program for such heat exchangers. Impracticality itself is not a sufficient reason for excluding any heat exchanger from some verification of performance.

15. What if performable HX testing conditions (off design) cannot be used to demonstrate acceptable heat transfer (i.e., low delta T combined with instrument accuracies)? Is maintenance inspection our only alternative? (Portland General Electric)

Answer

If reasonable results cannot be obtained from performance testing, then inspection or maintenance is an appropriate alternative. A licensee may, however, be able to justify another acceptable alternative.

16. If the utility performs a baseline test that exceeds the design requirements but is below the mfg [manufacturer's] rating for this component HX, does the NRC consider this as a concern in that "design margin" has been lowered? (Arkansas Power and Light)

Answer

No. The staff's concern is not that a licensee or applicant maintain the initially specified design margin. If the licensee or applicant chooses to operate with a reduced margin, this is acceptable provided the safety-related heat removal requirements are satisfied.

B. Maintenance of Heat Exchangers

1. To what extent can routine maintenance/cleaning of heat exchangers replace testing? (Philadelphia Electric)

Answer

A licensee or applicant should determine the appropriate frequency of testing or maintenance activities to ensure that the heat removal requirements for the service water system are satisfied. For a given heat exchanger, a licensee or applicant may elect to clean, replace, repair, or otherwise maintain it initially before beginning a routine testing program. If the licensee or applicant elects to not implement a routine testing program for the heat exchanger, then a routine maintenance program may be necessary to provide the sought assurance. In the absence of a routine test program, no basis may be available for detecting potential degradation of heat transfer performance. In the absence of such a basis, the frequency of maintenance may have to be a maximum value to provide the sought assurance.

2. Page 5, paragraph 4. If the maintenance period is known why can't a test be performed before maintenance to establish a data point for the required testing or maintenance? If the overall maintenance period has been 3 or more fuel cycles could this be used to establish the test frequency? Is it necessary to retest a heat exchanger after maintenance if the work performed was a restoration only (i.e., cleaning not tube plugging) and testing had previously been conducted with clean heat transfer surfaces? (Portland General Electric)

Answer

All these steps are acceptable alternatives to the program outlined in Enclosure 2 in the generic letter. The justifications that these alternative procedures ensure that the heat removal requirements for the service water system are satisfied should be documented and retained in appropriate plant records.

3. Recommended Action II paragraph 5 states that frequent regular maintenance is an acceptable alternative to testing. What is meant by "frequent regular maintenance"? Does this mean more frequently than if testing were performed? This paragraph further states that this alternative might apply to small heat exchangers, . . . located in low radiation areas. . . . Would low radiation areas be defined by ALARA [as low as is reasonably achievable] practices or less than 100 mr/hr? (Unidentified)

Answer

The licensee or applicant is to establish the frequency of periodic testing or regular maintenance once sufficient data have been collected. The frequency should ensure that unacceptable degradation does not occur between testing or maintenance cycles. Low radiation areas as intended in Generic Letter 89-13 are included in the licensee's ALARA program so that radiation levels will not preclude personnel access for maintenance and cleaning of heat exchangers.

4. GL 89-13 seems to imply that periodic maintenance (i.e., cleaning) of small accessible heat exchangers is acceptable in lieu of performance testing. If so, is a refueling maintenance frequency acceptable? (Northeast Utilities)

   Answer

   Yes. This is an acceptable initial frequency and may be acceptable in the long-term with justification based on data from a minimum of three refueling outages.

5. If maintenance is performed in lieu of testing for degraded performance of the heat exchanger, how extensive does the maintenance have to be? That is, does maintenance have to be performed on both sides of the HX or just on the service water side? (Niagara Mohawk Power)

   Answer

   Maintenance should be extensive enough to assure the heat removal requirements of the service water system are satisfied. See the answers to Questions III.B.1 and III.F.1.

6. Would a program involving inspection and maintenance activities in lieu of a performance test program be an acceptable program for all heat exchangers and components? (Nuclear Utility Backfit Action Reform Group [NUBARG])

   Answer

   Yes, if justification is provided.

7. Clarification of Item IV. B., Enclosure 2, on periodic visual inspection of small heat exchangers such as seal coolers. Are they included in the class to be inspected when the pump is inspected? (Nebraska Public Power District)

   Answer

   If the seal coolers in question are integral parts of larger components, such as pumps, then the coolers may be inspected visually during the regularly scheduled disassembly of the larger component. If not, then the seal coolers should be treated separately. Once it has been established that a small heat exchanger such as a seal cooler is performing satisfactorily, the licensee or applicant may choose to justify an extended program of periodic inspection (e.g., up to 5 years) on the basis of existing operating conditions, such as the cooling of loops not subject to fouling mechanisms.

8. ANO [Arkansas Nuclear One] is scheduled to chemically clean the entire SW system in the fall of 1990. Does this constitute an acceptable method to restore thermal performance in lieu of performance testing for the first outage? (Arkansas Power and Light)

<u>Answer</u>

The licensee or applicant should justify such an approach to satisfy this part of the generic letter. Since chemical cleaning is a corrective action, some followup verification such as visual examination or limited performance testing may be appropriate.

C. Number of Heat Exchangers To Be Tested

1. Is it acceptable to determine the most restrictive heat exchangers in each group for testing in lieu of testing every heat exchanger? (Philadelphia Electric)

Answer

The purpose of the generic letter is for licensees and applicants to assure that the heat removal requirements for the service water system are satisfied. If this can be done by the proposed program, then it is acceptable.

2. How much detail does the NRC expect for the response to Action II? Would the proposed test/maintenance/inspection method for each heat exchanger be necessary? (Public Service Electric and Gas)

Answer

Specific details of the licensee's or applicant's program in response to Action II should be developed and retained as part of plant records. Those heat exchangers not being included in programs under Action II should be identified and the basis given for their exclusion. Grouping of heat exchangers into categories based on the approach to be used would be acceptable.

3. Enclosure 2, page 2. The term "all heat exchangers" is used. Does this imply every heat exchanger of a given design must be tested or where more than one identical heat exchanger is used can one representative unit be selected? (Portland General Electric)

Answer

Recommended Action II calls for the testing of the heat transfer capability of all safety-related heat exchangers cooled by service water. The service water system is defined as the system or systems that transfer heat from safety-related structures, systems, or components to the ultimate heat sink. Each heat exchanger, regardless of redundancy, should be tested or maintained initially to establish that the heat removal requirements for the service water system are satisfied. Existence of identical conditions then can be used to determine the best test or maintenance frequencies to ensure that the heat removal requirements for the service water system are satisfied.

4. We would like to limit heat exchanger performance testing to one unit since the two units are identical. Is this an acceptable approach? (Houston Lighting and Power)

Answer

Not totally. See the answer to the previous question.

5. Is it acceptable to eliminate heat exchangers from the testing requirement of Action II if they are in parallel and/or in series with other heat exchangers which are tested and operated under similar service conditions (e.g., velocity, temperature, process fluid) (Ref. EPRI Heat Exchanger Performance Monitoring Guidelines for Service Water Systems)? (Commonwealth Edison)

Answer

Not totally. See the answer to Question III.C.3.

D. Frequency of Testing or Maintenance

1. Recommendation No. III [sic] does not specify a frequency for heat exchanger inspections. Is it the NRC's intent that the utility establish the frequency of these inspections? (GPU Nuclear)

Answer

Yes. Recommended Action II indicates limits. Initially, tests should be conducted at least once every fuel cycle. More frequent testing may be necessary to enable a conclusion that the heat removal requirements for the service water system are satisfied. After about three tests, a licensee or applicant may be in a position to set a different testing frequency. However, the finally determined testing frequency should not be less than once every 5 years.

2. Page 6, paragraph 1. Why were three tests chosen? Could a different number, more or less, be appropriate? (Portland General Electric)

Answer

The number three is the minimum number needed to establish a trend. A larger number would be appropriate, but a smaller number is insufficient.

3. Page 5, paragraph 5. What is meant by frequent regular maintenance? Can frequency be determined in a similar method as test frequency? (Portland General Electric)

Answer

Frequent regular maintenance is an acceptable alternative to Recommended Action II, which calls for heat exchanger performance testing. For small heat exchangers such as lube oil coolers, testing might be excessively burdensome compared with maintenance of the heat exchangers. A licensee or applicant can choose to routinely maintain the heat exchangers instead of testing them. Either the frequency of maintenance or the frequency of testing should be determined to ensure that the equipment will perform the intended safety functions during the intervals between maintenances or tests.

E. Schedule

1. In an effort to minimize the amount of time that a single, redundant division of safety-related equipment is out of service some utilities employ a "divisional outage" concept for major planned plant outages. By utilizing this concept significant maintenance work activities, i.e., system flow balance test, standby D/G [diesel generator] teardowns, electrical distribution bus work, etc., are performed on an alternating outage schedule for each division. This permits comprehensive maintenance on each division to be performed while reducing the overall impact on redundant safety system availability.

   The ability of a utility to implement and maintain a service water heat removal capability monitoring program would be significantly enhanced by the installation of permanent plant monitoring equipment. Installation of dedicated monitoring equipment would also reduce the impact of future testing on service water and heat exchanger availability.

   For a utility that employs the "divisional outage" concept and wishes to install permanent plant equipment to perform the system testing identified in Generic Letter 89-13, is it permissible to defer baseline data acquisition for one division of the service water system until the second refueling outage following the issuance of the generic letter? (Mississippi Power and Light)

   Answer

   This request appears to be reasonable for good cause. Any request for an adjusted schedule should be arranged through the appropriate project manager in the Office of Nuclear Reactor Regulation (NRR) of the NRC.

2. In reference to Recommended Action II of Generic Letter 89-13. (Niagara Mohawk Power)

   Asking an item of clarification Do all safety-related heat exchangers connected to or cooled by service water or raw water have to be tested or verified clean by maintenance, to insure satisfaction of the heat removal requirements, prior to plant startup following the first refueling outage beginning 9 months or more after the issuance of Gen. Ltr 89-13?

   Answer

   Yes.

   Reason for asking If a heat exchanger was cleaned 13 or possibly 18 months prior to issuance of Gen. Ltr 89-13 and found to be clean or tested and found acceptable and the current program does not call for recleaning or testing for 3 years then the program would have to be revised. Also trend data may already exist indicating that there is no need to clean or test on less than a 5-year interval. [This would also hold] if the heat exchanger is part of a larger component that is not scheduled for maintenance.

Answer

The generic letter is designed to provide flexibility in determining a justifiable alternative program for testing. The goal of the letter is to ensure that the heat removal requirements for the service water system are satisfied.

F. Closed-Cycle Systems

1. What is really required by the sentence on adequacy of chemistry control programs in the first paragraph of page 5 of the generic letter? (Kansas Gas and Electric)

Answer

Even though a closed cooling loop may contain water with controlled chemistry, the loop might be contaminated as a result of inleakage, inadequate chemistry controls, or materials in the system before the current chemistry control program became effective. An example of this was recently disclosed at the EPRI Service Water System Reliability Improvement Seminar at Charlotte, North Carolina, on November 6-8, 1989. In the internal study discussed there, optical examination of the primary side of the decay heat removal (DHR) heat exchanger (HX) tubes disclosed no fouling. The tubes were shiny bright. Optical examination of the closed component cooling water (CCW) HX, however, disclosed significant fouling. The tubes did not reflect any light. The problem was a paraffin-based packing material inadvertently left in the system when the plant was being constructed.

Suppose the licensee in this case can argue that it has a chemistry control program for water circulating through the CCW HX, but cannot show that the program has been in place since the system was filled initially. A proper response to the generic letter then would include testing the CCW HX. At any point in the program, if a finding of degraded heat transfer cannot be explained or remedied by maintenance in the open-cycle portion of the system, as would be possible in this case, the CCW HX should be tested and, depending on those results, the DHR HX should be tested. The process should be continued until the problem is remedied.

2. Does our CCWS [component cooling water system] need to be addressed as part of our response? We have recently shown, through eddy current testing of the CCW HTX's [heat exchangers], that the physical barrier between SW [service water] and CCW is adequate. Makeup to the CCW is via makeup water. (Wisconsin Public Service)

Answer

Not necessarily. See the answer to the previous question.

3. Page 5, paragraph 1. What level of documentation is required to justify excluding closed-cycle system heat exchangers from testing to verify heat transfer capability? (Portland General Electric)

Answer

The goal of the generic letter is to obtain assurance that the heat removal requirements for the service water system are satisfied. To exclude a closed-cycle system heat exchanger from testing, a licensee or applicant should show that the chemistry of the primary fluid and the heat transfer characteristics of the heat exchanger have been controlled since the system was first filled.

4. The ACRS [Advisory Committee on Reactor Safeguards] June 14, 1989, letter to the Commission noted five areas of concern with which NUBARG agrees. Some of the concerns were accommodated in the GL; however, we are interested to know the resolution of the following. (Nuclear Utility Backfit Action Reform Group [NUBARG])

   a. An intermediate closed cooling water system is exempt from the GL provided it is not subject to significant sources of contamination, is chemistry controlled, and does not reject heat directly to a heat sink. However, the adequacy of the chemistry control program must be verified over the total operating history of the plant. The ACRS questioned whether the absence of an adequate water chemistry control system over any part of the operating history of a closed-cycle system was adequate justification for including the system within the scope of the GL. How did the staff resolve this concern?

      Answer

      The staff relaxed its position on including closed-cycle cooling systems in Recommended Action II but added the precautionary recommendation that if degradation of heat transfer could not be explained or remedied by maintenance of the open-cycle part of the service water system, then testing may have to be selectively extended to the closed-cycle part of the system. See the answer to Question III.F.1.

   b. Are plants required to review closed cooling water system operating logs for the history of the plant to verify adequate chemistry control?

      Answer

      Licensees and applicants are required to assure that the safety-related heat removal requirements for the service water system are satisfied. If review of closed cooling water system operating logs for the history of the plant can help provide this assurance, then that review would be an acceptable part of the program.

G. <u>Miscellaneous</u>

1. Do both emergency service water systems and normal service water systems need to be reviewed? (Kansas Gas and Electric)

   <u>Answer</u>

   In some cases this may be necessary. The NRC is concerned about the safety-related effects of both systems. Sometimes the mode of operation of a service water system is changed under emergency conditions. This change may result in the introduction of uncontrolled water and thus the potential introduction of biofouling agents, corrosion products, and silt that may adversely affect the heat transfer performance of the system.

2. Page 6, paragraph 1. The generic letter does not specifically address testing of automatic safety features actuation which may be required to provide the required service water flow to safety-related heat exchangers. Does the NRC have any recommendations on functional tests of systems? (Portland General Electric)

   <u>Answer</u>

   The generic letter was written with the tacit assumption that all other regulatory conditions would be observed. In particular, functional testing required by technical specifications must be accomplished independently of the recommended actions of the generic letter. Where there is overlap, credit may be taken for the functional tests required by the technical specifications. The procedures, results, and considerations of such tests should be documented with the response to the generic letter and retained in appropriate plant records.

3. Recommended Action II paragraph 4 states tests should be performed following corrective action. Would bulleting tubes be considered as corrective actions? (Unidentified)

   <u>Answer</u>

   Yes.

4. Generic Letter 89-13 states that tests should be performed on heat exchangers before and after "corrective action" is performed. What is meant by "corrective action"? (Southern California Edison)

   <u>Answer</u>

   Corrective action is any action that improves the condition of the heat exchanger.

IV. ACTION III - ROUTINE INSPECTION AND MAINTENANCE

A. Recommendation III states, "Ensure by establishing a routine inspection and maintenance program . . . that corrosion, erosion . . . cannot degrade the performance of the safety-related systems supplied by service water." [Emphasis added.] It would seem unrealistic to assume that a program could be developed that will ensure absolutely no degradation of the system. Could you clarify that the intent here is to establish a program which will ensure that the system cannot degrade to the point at which its ability to perform its safety function is impaired? (Duke Power)

Answer

The NRC staff concurs in this interpretation.

B. Must all safety-related service water piping be cleaned or only the piping that is susceptible to corrosion buildup, i.e., low flow areas? Nondestructive examinations would be used to confirm the areas needed to be cleaned. (Wisconsin Public Service)

Answer

Recommended Action III is intended to provide assurance that the performance of open-cycle service water piping and components is not degraded as a result of corrosion, erosion, protective coating failure, silting, and biofouling. Once this assurance is made, the routine maintenance and inspection program can concentrate on those piping segments that are susceptible to these problems.

C. Would it be considered acceptable to omit from inspection piping which is practically inaccessible (i.e., underground piping) based on inspections of practically accessible piping? (Philadelphia Electric)

Answer

Inaccessibility itself would not be a sufficient reason for not inspecting piping. However, if additional justification including operational data and prior history is available, along with an evaluation that clearly shows that inspections would not be necessary, then inspection could be omitted.

D. Refer to Item III. Does the maintenance program have to include sampling of any crud or sediment found to determine its source; e.g., during routine maintenance a small amount of sediment was cleaned from a heat exchanger and the only documentation stated that it appeared to be a normal corrosion deposit? (Niagara Mohawk Power)

Answer

If the maintenance program can ensure that the heat removal requirements for the service water system are met, then it is acceptable. The better the root cause analysis of a problem is, however, the more effective will be the corrective action.

E. Refer to Item III. If minimum fouling is found during maintenance it should be acceptable to assume that the heat exchanger can still perform to the original design specification. Does the NRC have a problem with this assumption? (Niagara Mohawk Power)

Answer

The NRC staff cannot judge the adequacy of heat transfer capability based on the broad statement of "minimum" fouling. The licensee or applicant must determine what fouling level requires corrective action and justify the approach taken.

F. Under Specific Action III(A) on page 6 of the GL, what constitutes excessive accumulations of biofouling agents, corrosion products, and silt? (Nuclear Utility Backfit Action Reform Group [NUBARG])

Answer

The staff does not have a quantitative criterion for this parameter. If such accumulations degrade the heat transfer capability of the system such that the system cannot perform its safety-related function as shown by performance trend data, then such accumulations are excessive.

G. Are plant work requests adequate relevant documentation to support the inspection and maintenance documentation requirement of Specific Action III? (NUBARG)

Answer

Yes, as long as they can be made available to an NRC inspector.

H. Programs acceptable to the NRC in response to GL 89-13 Actions I and II were identified. What are some examples of acceptable inspection and maintenance programs in response to Action III? (Commonwealth Edison)

Answer

The NRC has not defined an acceptable program for Action III. However, the generic letter is designed to give the licensee or applicant sufficient flexibility in developing an appropriate program.

V. ACTION IV - SINGLE-FAILURE WALKDOWN

A. To what extent does this walkdown have to be performed? We are presently conducting a design-basis documentation reconstitution effort. A system walkdown is performed only if a problem is identified during documentation review. Walkdowns are not conducted all the time and are not full scope. Is the intent to complete walkdowns as required to ensure the system meets the licensing basis for the plant or to verify the as-built condition? (Public Service Electric and Gas)

<u>Answer</u>

The intent of the recommended action is to verify that the as-built condition of the system is sufficient to ensure performance of the intended function of the service water system. A design-basis reconstitution suffices for the walkdown inspection recommended here.

B. A service water system walkdown inspection was completed in 1986 at our plant. Can we take credit for that effort for this action or must we repeat it now to meet the 2-year criterion? (Niagara Mohawk Power)

<u>Answer</u>

You may take credit for the 1986 walkdown to meet this recommended action. The suggested time of 2 years to qualify the word "recent" was not meant to be rigidly interpreted. The NRC is interested in the walkdown being done now or recently, not in the distant past.

C. Does the system walkdown take into account piping, valves, and in-line components? What about cabling walkdown? Is our 79-14 walkdown sufficient to address this? (Wisconsin Public Service)

<u>Answer</u>

The system walkdown should ensure that the system's safety-related function can be accomplished in the event of failure of a single active component. Cabling walkdowns are thus not in the scope of Generic Letter 89-13. The intent of Recommended Action IV is to make maximum use of other pertinent activities in reviewing the system, but it is not sufficient to depend on 10-year-old reviews to ascertain the condition of the system today. However, the staff understands that Bulletin 79-14, "Seismic Analyses for As-Built Safety-Related Piping Systems," is not closed at all plants; therefore, if the walkdowns have been done recently, they would be acceptable. Activities included in the Individual Plant Examination (IPE) program may also constitute an acceptable response to this recommended action.

D. Recommendation No. IV discusses system walkdown inspections. GPU Nuclear assumes that the intent of the walkdown is down to the level of the flow diagram only. Does the NRC agree with this assumption or do we intend for a more detailed walkdown? (GPU Nuclear)

Answer

See the answer to the previous question. Single-failure inadequacies can occur in control systems as well as equipment in which water flows. The staff notes that single-failure inadequacies have been found at some plants apart from routine surveillance procedures.

E. Page 6, paragraph IV. Are there any specific requirements which are new that should be added into existing single-failure analysis? Explain what is meant by "reconstitution of the design basis of the system is not intended." (Portland General Electric)

Answer

As discussed in the answers to the next two questions, the staff does not intend that the licensing basis of a given plant be changed. Recommended Action IV for single-failure walkdown was not designed to incorporate any new feature into existing single-failure analysis techniques. The phrase "reconstitution of the design basis of the system is not intended" refers to excessively difficult determinations of design data. For example, this may be the case for small skid-mounted heat exchangers that were purchased as piece parts of larger units of equipment and for which the vendor may not have provided design data to the licensee or applicant. It would be enough to demonstrate that the equipment module of which the heat exchanger is a part could do its job.

F. Please elaborate on the requirements of Item 4. Specifically, what is intended by confirmation of the performance of the service water system in accordance with the design basis, without a reconstitution of the design basis? Also, is it intended by this requirement to perform a complete single-failure analysis of the service water system? (Northeast Utilities)

Answer

The licensee or applicant is expected to confirm that the installed as-built system satisfies the design requirements stated in the plant's licensing basis, that is, the final safety analysis report (FSAR), the technical specifications, and licensing documentation. See the answers to Questions V.C and V.D.

G. The generic letter states that the licensee should verify that the service water system is in accordance with the licensing basis of the plant. Is the licensing basis, in the context of this generic letter, considered to be the FSAR and tech specs [technical specifications] or will a more expansive interpretation be used? (Wisconsin Electric Power)

Answer

The licensing basis is as defined in the FSAR, technical specifications, and other licensing documentation. It is not the staff's intent that the licensing basis be redefined when addressing Generic Letter 89-13.

H. With regard to Action IV which requests confirmation that the service water system will perform its intended function in accordance with the licensing basis for the plant, which specific licensing basis must be reconfirmed at this time? Only the single active failure review? (Commonwealth Edison)

Answer

The licensing basis is considered to include the FSAR, technical specifications, and licensing documentation. See the answers to the previous two questions.

I. Action item 4 of GL 89-13 states that system walkdown inspections are required to confirm the as-built configuration of the service water systems. As a recently licensed plant, we are confident that our configuration control program satisfies this requirement. We believe system walkdowns are unnecessary for STPEGS [South Texas Project Electric Generating Station]. (Houston Lighting and Power)

Answer

This position appears to be reasonable for good cause. Ongoing programs that contain results pertinent to Generic Letter 89-13 should be referenced in the response as justification for an equally effective program and retained in appropriate plant records.

J. If other design-related issues are being addressed by other regulatory actions is it acceptable to exclude them from the scope of review for Action IV? (Commonwealth Edison)

Answer

Yes. See the answer to the previous question.

K. Should the single-failure analysis of the SW system include motive power (electrical/pneumatic, etc.) to active components (motor, valve, etc.)? If so, should it be limited only to the delivery of the motive power to the component, and not the single-failure reliability of the motive power sources (i.e., do not need to do single-failure analysis on motive power system)? (Carolina Power and Light)

Answer

The licensee or applicant should consider single failures in power-operated equipment or components that are part of the service water system. Single failures in power supply systems themselves do not need to be considered under Generic Letter 89-13.

VI. ACTION V - PROCEDURES REVIEW

A. Please discuss what constitutes the desired response for Action Item 5. (Confirming the adequacy of maintenance practices, operating and emergency procedures, and training that involves the service water system). The letter states that the confirmation "should include" recent reviews of practices, procedures, and training modules. Please provide some guidance for performing an adequate review. Also, are there other actions which the NRC recommends as part of the confirmation? (South Carolina Electric and Gas)

Answer

The staff has no specific guidance on what procedures, training, and maintenance practices should be evaluated or revised. The intent of this item is to increase personnel awareness of the importance of the service water system with the aim of reducing human errors. Refer to the wording in Action Item V in Generic Letter 89-13. Personnel or procedural errors were identified in the Office for Analysis and Evaluation of Operational Data (AEOD) case study (NUREG-1275, Volume 3, November 1988) discussed in the generic letter as a significant cause of service water system failures and degradations. One acceptable response would be to review those maintenance practices, operating and emergency procedures, and training modules that pertain to the events listed in the appendices in the AEOD case study.

ENCLOSURE 4

TO

ATTACHMENT 4 TO TXX-92410

NUREG-1172, River Bend Technical Specifications
November 1985, Section 3/4.7.1.

Pages:

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NUREG-1172

Technical Specifications
River Bend Station

Docket No. 50-458

Appendix "A" to
License No. NPF-47

Issued by the
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Office of Nuclear Reactor Regulation

November 1985

3/4.7 PLANT SYSTEMS

3/4.7.1 SERVICE WATER SYSTEMS

STANDBY SERVICE WATER SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.1.1 At least two independent standby service water (SSW) system subsystems, with each subsystem comprised of:

a. Two OPERABLE SSW pumps, and

b. An OPERABLE flow path capable of taking suction from the standby cooling tower basin and transferring the water through associated systems and components required to be OPERABLE,

shall be OPERABLE:

a. In OPERATIONAL CONDITION 1, 2, and 3, two subsystems.

b. In OPERATIONAL CONDITION 4, 5 and*, the subsystem(s) associated with systems and components required OPERABLE by Specifications 3.4.9.2, 3.5.2, 3.8.1.2, 3.9.11.1, and 3.9.11.2.

APPLICABILITY: OPERATIONAL CONDITIONS 1, 2, 3, 4, 5, and *.

ACTION:

a. With the SSW flow path to one or more systems or components inoperable, declare the associated systems or components inoperable and take the required action.

b. In OPERATIONAL CONDITION 1, 2, or 3:

   1. With one SSW pump inoperable restore the inoperable pump to OPERABLE status within 30 days or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

   2. With one SSW pump in each subsystem inoperable restore at least one to OPERABLE status within 7 days or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

   3. With one SSW subsystem otherwise inoperable, restore the inoperable subsystem to OPERABLE status within 72 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

*When handling irradiated fuel in the primary containment or Fuel Building.

LIMITING CONDITION FOR OPERATION (Continued)

ACTION: (Continued)

4. With both SSW subsystems otherwise inoperable, be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN** within the following 24 hours.

c. With only one SSW pump and its associated flow path OPERABLE, restore at least two pumps with at least one flow path to OPERABLE status within 72 hours or:

1. In OPERATIONAL CONDITION 4 or 5, declare the associated equipment inoperable and take the ACTION required by Specifications 3.4.9.2, 3.5.2, 3.8.1.2, 3.9.11.1, and 3.9.11.2.

2. In Operational Condition *, verify adequate cooling for the diesel generators required to be OPERABLE or declare the associated diesel generator inoperable and take the ACTION required by Specification 3.8.1.2. The provisions of Specification 3.0.3 are not applicable.

SURVEILLANCE REQUIREMENTS

4.7.1.1 At least the above required standby service water system subsystem(s) shall be demonstrated OPERABLE:

a. At least once per 31 days by verifying that each valve in the flow path, that is not locked, sealed or otherwise secured in position, is in its correct position.

b. At least once per 18 months during shutdown by verifying that each automatic valve actuates to the correct position and each pump starts on a normal service water low-pressure signal.

*When handling irradiated fuel in the primary containment or Fuel Building.
**Whenever both RHR shutdown cooling mode loops are inoperable, if unable to attain COLD SHUTDOWN as required by this ACTION, maintain reactor coolant temperature as low as practical by use of alternate heat removal methods.

3/4.7.1 STANDBY SERVICE WATER SYSTEM

The OPERABILITY of the service water system and ultimate heat sink ensure that sufficient cooling capacity is available for continued operation of safety-related equipment during normal and accident conditions. The redundant cooling capacity of these systems, assuming a single failure, is consistent, within acceptable limits, with the assumptions used in the accident analyses.

3/4.7.2 MAIN CONTROL ROOM AIR CONDITIONING SYSTEM

The OPERABILITY of the main control room air conditioning system ensures that (1) the ambient air temperature does not exceed the allowable temperature for continuous duty rating for the equipment and instrumentation cooled by this system and (2) the control room will remain habitable for operations personnel during and following all design basis accident conditions. Continuous operation of the system with the heaters OPERABLE for 10 hours during each 31 day period is sufficient to reduce the buildup of moisture on the adsorbers and HEPA filters. The OPERABILITY of this system, in conjunction with control room design provisions, is based on limiting the radiation exposure to personnel occupying the control room to 5 rem or less whole body or its equivalent. This limitation is consistent with the requirements of General Design Criterion 19 of Appendix "A", 10 CFR Part 50.

3/4.7.3 REACTOR CORE ISOLATION COOLING SYSTEM

The reactor core isolation cooling (RCIC) system is provided to assure adequate core cooling, in the event of reactor isolation from its primary heat sink and the loss of feedwater flow to the reactor vessel, without requiring actuation of any of the Emergency Core Cooling System equipment. The RCIC system is conservatively required to be OPERABLE whenever reactor pressure exceeds 150 psig. This pressure is substantially below that for which the low pressure core cooling systems can provide adequate core cooling for events requiring the RCIC system.

The RCIC system specifications are applicable during OPERATIONAL CONDITIONS 1, 2 and 3, when reactor vessel pressure exceeds 150 psig, because RCIC is the primary non-ECCS source of emergency core cooling when the reactor is pressurized.

With the RCIC system inoperable, adequate core cooling is assured by the OPERABILITY of the HPCS system which justifies the specified 14 day out-of-service period.

ENCLOSURE 5

TO

ATTACHMENT 4 TO TXX-92410

NUREG-1279, Beaver Valley 2 Technical Specifications
August 1987, Section 3/4.7.4 and 3/4.7.13.

Pages:

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NUREG-1279

Technical Specifications

Beaver Valley Power Station, Unit 2

Docket No. 50-412

Appendix "A" to
License No. NPF-73

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August
~~July~~ 1987

3/4.7.4 SERVICE WATER SYSTEM (SWS)

LIMITING CONDITION FOR OPERATION

3.7.4.1 At least two service water subsystems supplying safety related equipment shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

With one less than two SWS subsystems OPERABLE, restore at least two subsystems to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.7.4.1 At least two SWS subsystems shall be demonstrated OPERABLE:

a. Verify that each pump develops the required differential pressure and flow rate when tested in accordance with the requirements of Section 4.0.5.

b. At least once per 31 days by verifying that each valve (manual, power operated or automatic servicing safety related equipment that is not locked, sealed, or otherwise secured in position, is in its correct position.

c. At least once per 18 months during shutdown, by cycling each power operated valve servicing safety related equipment that is not testable during plant operation, through at least one complete cycle of full travel.

3/4.7.13 STANDBY SERVICE WATER SYSTEM (SWE)

LIMITING CONDITION FOR OPERATION

3.7.13.1 At least one standby service water subsystem shall be OPERABLE.

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

ACTION:

With less than one SWE subsystem OPERABLE, restore at least one subsystem to OPERABLE status within 7 days or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following thirty hours.

SURVEILLANCE REQUIREMENTS

4.7.13.1 At least one SWE subsystem shall be demonstrated OPERABLE:

a. By verifying that each pump develops at least 109 psid differential pressure while pumping through its test flow line when tested pursuant to Specification 4.0.5.

b. At least once per 18 months during shutdown by starting a Standby Service Water System Pump, shutting down one Service Water System Pump, and verifying that the Standby Service Water Subsystem provides at least 8584 gpm cooling water to that portion of the Service Water System under test for at least 2 hours.

3/4.7 PLANT SYSTEMS

BASES

3/4.7.1.5 MAIN STEAM LINE ISOLATION VALVES

The OPERABILITY of the main steam line isolation valves ensures that no more than one steam generator will blow down in the event of a steam line rupture. This restriction is required to 1) minimize the positive reactivity effects of the Reactor Coolant System cooldown associated with the blowdown, and 2) limit the pressure rise within containment in the event the steam line rupture occurs within containment. The OPERABILITY of the main steam isolation valves within the closure times of the surveillance requirements are consistent with the assumptions used in the accident analyses.

3/4.7.2 STEAM GENERATOR PRESSURE/TEMPERATURE LIMITATION

The limitation on steam generator pressure and temperature ensures that the pressure induced stresses in the steam generators do not exceed the maximum allowable fracture toughness stress limits. The limitations of 70°F and 200 psig are based on a steam generator average impact values taken at 10°F and are sufficient to prevent brittle fracture.

3/4.7.3 PRIMARY COMPONENT COOLING WATER SYSTEM

The OPERABILITY of the primary component cooling water system ensures that sufficient cooling capacity is available for continued operation of safety related equipment during normal and accident conditions. The redundant cooling capacity of this system, assuming a single failure, is consistent with the assumptions used in the accident analyses.

3/4.7.4 SERVICE WATER SYSTEM

The OPERABILITY of the service water system ensures that sufficient cooling capacity is available for continued operation of safety related equipment during normal and accident conditions. The redundant cooling capacity of this system, assuming a single failure, is consistent with the assumptions used in the accident conditions.

3/4.7.5 ULTIMATE HEAT SINK

The limitations on the ultimate heat sink level and temperature ensure that sufficient cooling capacity is available to either 1) provide normal cooldown of the facility, or 2) to mitigate the effects of accident conditions within acceptable limits.

The limitations on minimum water level and maximum temperature are based on providing a 30 day cooling water supply to safety related equipment without

ENCLOSURE 6

TO

ATTACHMENT 4 TO TXX-92410

NUREG-0949, St. Lucie Unit 2 Technical Specifications
April 1983, Section 3/4.7.4.

Pages:

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NUREG-0949

Technical Specifications

St. Lucie Plant
Unit No. 2

Docket No. 50-389

Appendix "A" to
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3/4.7.4 INTAKE COOLING WATER SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.4 At least two independent intake cooling water loops shall be OPERABLE.*

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

ACTION:

With only one intake cooling water loop OPERABLE, restore at least two loops to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.7.4 At least two intake cooling water loops shall be demonstrated OPERABLE:

a. At least once per 31 days by verifying that each valve (manual, power-operated, or automatic) servicing safety-related equipment that is not locked, sealed or otherwise secured in position, is in its correct position.

b. At least once per 18 months during shutdown, by verifying that each automatic valve servicing safety-related equipment actuates to its correct position on an SIAS test signal.

*When ICW pump 2C is being used to satisfy the requirements of this specification, the alignment of the discharge valves must be verified to be consistent with the appropriate power supply at least once per 24 hours.

3/4.7.1.7 ATMOSPHERIC DUMP VALVES

The limitation on maintaining the atmospheric dump valves in the manual mode of operation is to ensure the atmospheric dump valves will be closed in the event of a steam line break. For the steam line break with atmospheric dump valve control failure event, the failure of the atmospheric dump valves to close would be a valid concern were the system to be in the automatic mode during power operations.

3/4.7.2 STEAM GENERATOR PRESSURE/TEMPERATURE LIMITATION

The limitation on steam generator pressure and temperature ensures that the pressure-induced stresses in the steam generators do not exceed the maximum allowable fracture toughness stress limits. The limitations to 100°F and 200 psig are based on a steam generator RT_{NDT} of 20°F and are sufficient to prevent brittle fracture.

3/4.7.3 COMPONENT COOLING WATER SYSTEM

The OPERABILITY of the Component Cooling Water System ensures that sufficient cooling capacity is available for continued operation of safety-related equipment during normal and accident conditions. The redundant cooling capacity of this system, assuming a single failure, is consistent with the assumptions used in the safety analyses.

3/4.7.4 INTAKE COOLING WATER SYSTEM

The OPERABILITY of the Intake Cooling Water System ensures that sufficient cooling capacity is available for continued operation of equipment during normal and accident conditions. The redundant cooling capacity of this system, assuming a single failure, is consistent with the assumptions used in the safety analyses.

ENCLOSURE 7

TO

ATTACHMENT 4 TO TXX-92410

NUREG-0973, Waterford 3 Technical Specifications
December 1984, Section 3/4.7.3.

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NUREG-0973

Technical Specifications
Waterford Steam Electric Station, Unit No. 3

Docket No. 50-382

Appendix "A" to
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3/4.7.3 COMPONENT COOLING WATER AND AUXILIARY COMPONENT COOLING WATER SYSTEMS

LIMITING CONDITION FOR OPERATION

3.7.3 At least two independent component cooling water and associated auxiliary component cooling water trains shall be OPERABLE.

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

ACTION:

With only one component cooling water and associated auxiliary component cooling water train OPERABLE, restore at least two trains to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.7.3 Each component cooling water and associated auxiliary component cooling water train shall be demonstrated OPERABLE:

a. At least once per 31 days by verifying that each valve (manual, power-operated, or automatic) servicing safety-related equipment that is not locked, sealed, or otherwise secured in position, is in its correct position.

b. At least once per 18 months, during shutdown, by verifying that each automatic valve servicing safety-related equipment actuates to its correct position on SIAS and CSAS test signals.

c. At least once per 18 months by verifying that each component cooling water and associated auxiliary component cooling water pump starts automatically on an SIAS test signal.

3/4.7.1.4 ACTIVITY

The limitations on secondary system specific activity ensure that the resultant offsite radiation dose will be limited to a small fraction of 10 CFR Part 100 limits in the event of a steam line rupture. This dose also includes the effects of a coincident 1 gpm primary to secondary tube leak in the steam generator of the affected steam line and a concurrent loss-of-offsite electrical power. These values are consistent with the assumptions used in the safety analyses.

3/4.7.1.5 MAIN STEAM LINE ISOLATION VALVE

The OPERABILITY of the main steam line isolation valves ensures that no more than one steam generator will blow down in the event of a steam line rupture. This restriction is required to (1) minimize the positive reactivity effects of the Reactor Coolant System cooldown associated with the blowdown, and (2) limit the pressure rise within containment in the event the steam line rupture occurs within containment. The OPERABILITY of the main steam isolation valves within the closure times of the Surveillance Requirements are consistent with the assumptions used in the safety analyses.

3/4.7.2 STEAM GENERATOR PRESSURE/TEMPERATURE LIMITATION

The limitation on steam generator secondary pressure and temperature ensures that the pressure induced stresses in the steam generators do not exceed the maximum allowable fracture toughness stress limits. The limitation to 115°F and 210 psig is based on a steam generator RT_{NDT} of 40°F and is sufficient to prevent brittle fracture. Below this temperature of 115°F the system pressure must be limited to a maximum of 20% of the secondary hydrostatic test pressure of 1375 psia (corrected for instrument error). The limitations on the primary side of the steam generator are bounded by the restrictions on the reactor coolant system in Specification 3.4.8.1.

3/4.7.3 COMPONENT COOLING WATER AND AUXILIARY COMPONENT COOLING WATER SYSTEMS

The OPERABILITY of the component cooling water system and its corresponding auxiliary component cooling water system ensures that sufficient cooling capacity is available for continued operation of safety-related equipment during normal and accident conditions. The redundant cooling capacity of these systems, assuming a single failure, is consistent with the assumptions used in the safety analyses.

ENCLOSURE 8

TO

ATTACHMENT 4 TO TXX-92410

NUREG-1287, Palo Verde Unit 3 Technical Specifications
November 1987, Section 3/4.7.4.

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FOR INFORMATION ONLY

NUREG-1287

Technical Specifications

Palo Verde Nuclear Generating Station, Unit No. 3

Docket No. STN 50-530

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3/4.7.3 ESSENTIAL COOLING WATER SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.3 At least two independent essential cooling water loops shall be OPERABLE.

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

ACTION:

With only one essential cooling water loop OPERABLE, restore at least two loops to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.7.3 At least two essential cooling water loops shall be demonstrated OPERABLE:

a. At least once per 31 days by verifying that each valve (manual, power-operated, or automatic) servicing safety-related equipment that is not locked, sealed, or otherwise secured in position, is in its correct position.

b. At least once per 18 months during shutdown, by verifying that each automatic valve servicing safety-related equipment actuates to its correct position on an SIAS test signal.

c. At least once per 18 months during shutdown, by verifying that the essential cooling water pumps start on an SIAS test signal.

d. At least once per 18 months during shutdown, by verifying that each valve (manual, power-operated, or automatic) servicing safety-related equipment that is locked, sealed, or otherwise secured in position, is in its correct position.

3/4.7.4 ESSENTIAL SPRAY POND SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.4 At least two independent essential spray pond loops shall be OPERABLE.

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

ACTION:

With only one essential spray pond loop OPERABLE, restore at least two loops to OPERABLE status within 72 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.7.4.1 At least two essential spray pond loops shall be demonstrated OPERABLE at least once per 31 days by verifying that each valve (manual, power-operated, or automatic) servicing safety-related equipment that is not locked, sealed, or otherwise secured in position, is in its correct position.

4.7.4.2 Once per 18 months during shutdown, verify that each valve (manual, power-operated, or automatic) servicing safety-related equipment that is locked, sealed, or otherwise secured in position, is in its correct position.

3/4.7.1.4 ACTIVITY

The limitations on secondary system specific activity ensure that the resultant offsite radiation dose will be limited to a small fraction of 10 CFR Part 100 limits in the event of a steam line rupture. This dose also includes the effects of a coincident 1 gpm primary-to-secondary tube leak in the steam generator of the affected steam line and a concurrent loss-of-offsite electrical power. These values are consistent with the assumptions used in the safety analyses.

3/4.7.1.5 MAIN STEAM LINE ISOLATION VALVES

The OPERABILITY of the main steam line isolation valves ensures that no more than one steam generator will blow down in the event of a steam line rupture. This restriction is required to (1) minimize the positive reactivity effects of the Reactor Coolant System cooldown associated with the blowdown, and (2) limit the pressure rise within containment in the event the steam line rupture occurs within containment. The OPERABILITY of the main steam isolation valves within the closure times of the surveillance requirements are consistent with the assumptions used in the safety analyses.

3/4.7.1.6 ATMOSPHERIC DUMP VALVES

The limitation on maintaining the nitrogen accumulator at a pressure $\geq$ 400 psig is to ensure that a sufficient volume of nitrogen is in the accumulator to operate the associated ADV which holds the plant at hot standby while dissipating core decay heat or which allows a flow of sufficient steam to maintain a controlled reactor cooldown rate. A pressure of 400 psig retains sufficient nitrogen volume for 4 hours of operation at hot standby plus 6.5 hours of operation to reach cold shutdown under natural circulation conditions in the event of failure of the normal control air system.

3/4.7.2 STEAM GENERATOR PRESSURE/TEMPERATURE LIMITATION

The limitation on steam generator pressure and temperature ensures that the pressure induced stresses in the steam generators do not exceed the maximum allowable fracture toughness stress limits. The limitations to 120°F and 230 psig are based on a steam generator RT_{NDT} of 40°F and are sufficient to prevent brittle fracture.

3/4.7.3 ESSENTIAL COOLING WATER SYSTEM

The OPERABILITY of the essential cooling water system ensures that sufficient cooling capacity is available for continued operation of safety-related equipment during normal and accident conditions. The redundant cooling capacity of this system, assuming a single failure, is consistent with the assumptions used in the safety analyses.

3/4.7.4 ESSENTIAL SPRAY POND SYSTEM

The OPERABILITY of the essential spray pond system ensures that sufficient cooling capacity is available for continued operation of equipment during normal and accident conditions. The redundant cooling capacity of this system, assuming a single failure, is consistent with the assumptions used in the safety analyses.

3/4.7.5 ULTIMATE HEAT SINK

The limitations on the ultimate heat sink level and temperature ensure that sufficient cooling capacity is available to either (1) provide normal cooldown of the facility, or (2) to mitigate the effects of accident conditions within acceptable limits.

The limitations on minimum water level and maximum temperature are based on providing a 27-day cooling water supply to safety-related equipment without exceeding their design basis temperature and is consistent with the intent of the recommendations of Regulatory Guide 1.27, "Ultimate Heat Sink for Nuclear Plants," March 1974.

3/4.7.6 ESSENTIAL CHILLED WATER SYSTEM

The OPERABILITY of the essential chilled water system ensures that sufficient cooling capacity is available for continued operation of equipment and control room habitability during accident conditions. The redundant cooling capacity of this system, assuming a single failure, is consistent with the assumptions used in the safety analyses.

The Essential Chilled Water System (ECWS), in conjunction with respective emergency HVAC units, is required in accordance with Specification Definition 1.18 to provide heat removal in maintaining the various Engineered Safety Features (ESFs) room space design temperatures below the associated equipment qualification limits for the range of Design Basis Accident conditions. The normal HVAC system is redundant to the emergency HVAC system in maintaining the space design conditions of required safety systems during normal operating conditions and Design Basis Accident Conditions not involving seismic events or loss of offsite power. A seven (7) day Action requirement is for a single ECWS out of service, based on the high reliability of offsite power and availability of the normal HVAC system. The normal HVAC system contains two 100% redundant chillers. Action requirements are provided to ensure operability of the vital bus inverters and emergency battery chargers, by verifying within one hour that the normal HVAC system is providing space cooling to the vital power distribution rooms. The Action requirement is provided to establish within 8 hours operability of the safe shutdown systems which do not depend on the inoperable ECWS. The 8 hour period provides a reasonable time in which to establish operability of this complement of key safety systems. This requirement ensures that a functional train of safe shutdown equipment is available to put the plant in a safe, stable condition for the most probable abnormal operational occurences. An Action requirement of 24 hours is provided to establish operability of the remaining required safety systems which do not depend on the inoperable ECWS.

ATTACHMENT 5 TO TXX-92410

REDUCED PRESSURE

INTEGRATED LEAKAGE RATE TESTING

CONTENTS:

DESCRIPTION AND ASSESSMENT

I. BACKGROUND

Permission to perform a Containment Reduced Pressure Test in lieu of a Containment Peak Pressure Test during preoperational, periodic and supplemental tests has been removed.

10 CFR 50 Appendix J Section III.A.4.a allows a Type A Containment Integrated Leakage Rate Test (ILRT) to be performed at a reduced pressure Pt, not less than 0.50 Pa, if a correlation between the reduced pressure ILRT test and the Peak Pressure ILRT can be made to ensure that the total Containment leakage volume will not exceed the value assumed in the Safety Analyses at the Peak accident pressure. This reduced pressure test is initially performed during preoperational Startup tests in order to apply this correlation for future periodic ILRTs. The review of data collected by the American Nuclear Insurers (ANI) for 50 pairs of pre-operational ILRTs conducted at both peak and reduced pressure does not support a clear correlation between reduced pressure and peak leak rates. Therefore, any relationship between leakage rates determined during pre-operational testing cannot be reasonably presumed to exist for extended periods of time. During years of operation, the dominant leakage paths at any plant will tend to change due to operational events, modifications and maintenance. Testing and failure experience has shown that some leakage testing failures were due to the inception of leaks brought on by increasing pressure. Using the Unit 1 Containment reduced pressure test results, a satisfactory correlation could not be made. In addition, the proposed revision to 10 CFR 50 Appendix J does not allow reduced pressure tests to be used for periodic ILRT because it has not been demonstrated that one can extrapolate a leakage rate from a reduced pressure test to a leakage rate under full pressure.

II. DESCRIPTION OF TECHNICAL SPECIFICATION CHANGE REQUEST

This request proposes to remove the option of performing a Containment Integrated Leakage Rate at pressure less than the peak accident pressure in the Comanche Peak Steam Electric Station (CPSES) Unit 1 Technical Specification 3/4.6.1.2. Specifically, LCO 3.6.1.2a and ACTION, Surveillance 4.6.1.2a, b, c and Bases 3/4.6.1.2 are revised to remove the option for allowing an overall integrated leakage rate to be performed at less than or equal to 50 percent of the peak accident pressure.

III. ANALYSIS

Pre-operational Integrated Leak Rate Testing (ILRT) of the reactor containment is conducted after completion of the Structural Integrity Test (SIT). The original intent of conducting a reduced pressure test was to allow development of a correlation between reduced pressure and peak pressure leak rates. Since 10 CFR 50 Appendix J currently allows required periodic ILRTs to be performed at reduced pressure this correlation would theoretically allow the prediction of peak pressure leak rates without performing further peak pressure tests.

The collection of experience data does not support a clear correlation between reduced pressure and peak pressure leak rates.

The ANI proposed draft position indicates that testing and failure experience has shown that some leakage testing failures were clearly due to the inception of leaks brought on by increasing pressure. That these types of pressure-related failures demonstrate that conducting a successful leakage rate test at reduced pressure cannot assure that leakage integrity will be maintained at peak pressure. A leakage path closed at lower pressure may be open at peak pressure. Thus, it is not clear how the results of reduced pressure leakage tests can be used with confidence to demonstrate that the leakage rate at peak pressure will be less than the maximum allowed by the Technical Specification for peak pressure conditions.

Based on the above, the proposed changes to the CPSES Technical Specification eliminates the option of performing a reduced pressure ILRT. The requirements for pre-operational leak rate testing are still satisfied by conducting the peak pressure ILRT. Therefore, 10 CFR 50 Appendix J requirements for periodic ILRTs for CPSES will be satisfied by conducting peak pressure tests.

This course of action is consistent with that taken by other utilities. Both the Limerick Station and the South Texas Project (STP) did not perform reduced pressure ILRTs for establishing the correlation between reduced pressure and peak pressure leak rates. Limerick and STP performed the ILRT at peak pressure only.

IV. SIGNIFICANT HAZARDS CONSIDERATION DETERMINATION

TU Electric has evaluated the no significant hazards considerations involved with this proposed change in accordance with the three standards set forth in 10 CFR 50.92(c) as discussed below.

Does the proposed change:

1. Involve a significant increase in the probability or consequences of an accident previously evaluated?

   The proposed change is related to elimination of the option of performing reduced pressure ILRT. The pre-operational ILRT at peak design pressure for the Unit 2 containment structure will still be conducted. The intent of conducting a reduced pressure test is to allow for development of a correlation between reduced pressure and peak pressure leak rates. Since 10 CFR 50 Appendix J currently allows required periodic ILRTs to be performed at reduced pressure this correlation would theoretically allow the prediction of peak pressure leak rates without performing further peak pressure tests. The proposed change will require that the periodic ILRTs that must be performed in accordance with 10 CFR 50 Appendix J are conducted at peak pressure. Since testing at peak pressure provides the most accurate leak rate information, elimination of the reduced pressure ILRT does not create an increase in the probability or consequences of an accident.

2. Create the possibility of a new or different kind of accident from any accident previously evaluated?

   This change eliminates the option to perform periodic ILRTs as permitted by 10 CFR 50 Appendix J at reduced pressure. Since testing at peak pressure provides the most accurate leak rate information, elimination of the reduced pressure ILRT does not create the possibility of a new or different kind of accident from those previously evaluated.

3. Involve a significant reduction in the margin of safety as defined by the bases of the Technical Specifications?

   Since elimination of the option of performing reduced pressure ILRT is accompanied by a commitment to conduct the periodic ILRTs required by 10 CFR 50 Appendix J at peak pressure, there is no reduction in the margin of safety. In addition, conducting the periodic ILRTs at peak pressure will not adversely effect the performance of other components within the pressure boundary. The peak pressure introduced during ILRT represents the design pressure for other components within the boundary. Therefore, these components are designed to withstand the pressure that would be introduced during the peak pressure ILRT.

V. ENVIRONMENTAL EVALUATION

10 CFR 51.22(b) specifies the criteria for categorical exclusions from the requirement for a specific environmental assessment per 10 CFR 51.21. This amendment request meets the criteria specified in 10 CFR 51.22(c)(9). Specific criteria contained in this section are discussed below.

(i) the amendment involves no significant hazards consideration.

As demonstrated in the Significant Hazards Consideration Determination, the requested license amendment does not involve any significant hazards considerations.

(ii) there is no significant change in the types or significant increase in the amounts of any effluents that may be released offsite.

The requested license amendment involves no change to the facility and does not significantly alter the manner of operation in a way which could cause an increase in the amounts of effluents or create new types of effluents.

(iii) there is no significant increase in individual or cummulative occupational radiation exposure.

The proposed changes do not impact plant design features or operations that affect radiation protection, radioactive effluent processing, radioactive waste handling, or radiological environmental monitoring. The changes do not result in additional exposure by personnel nor affect levels of radiation present. The proposed changes do not result in significant individual or cummulative occupational radiation exposure.

Based on the above, it is concluded that there will be no impact on the environment resulting from this change and the change meets the criteria specified in 10 CFR 51.22 for a categorical exclusion from the requirements of 10 CFR 51.21 relative to a specific environmental impact statement or environmental assessment by the Commission.

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, 0.10% by weight of the containment air per 24 hours at P_a, 48.3 psig~~, or~~.

~~2) Less than or equal to L_t, 0.05% by weight of the containment air per 24 hours at a reduced pressure of P_t, 24.15 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 the measured overall integrated containment leakage rate exceeding 0.75 L_a ~~or 0.75 L_t, as applicable~~, or 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 0.75 L_a ~~or less than 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:

a. Three Type A tests (Overall Integrated Containment Leakage Rate) shall be conducted at 40 ± 10 month intervals during shutdown at a pressure not less than ~~either~~ P_a, 48.3 psig ~~or at P_t, 24.15 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;

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 18 months 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 test by verifying that the supplemental test result, L_c, is in accordance with the appropriate following equation:

$| L_c - (L_{am} + L_o) | \le 0.25 La$ ~~or $| L_c - (L_{tm} + L_o) | \le 0.25 L_t$~~

where L_{am} ~~or L_{tm}~~ is the measured Type A test leakage and L_o is the superimposed leak;

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

3) Requires that the rate at which gas is injected into the containment or bled from the containment during the supplemental test is between 0.75 L_a and 1.25 L_a ~~or 0.75 L_t and 1.25 L_t~~.

d. Type B and C tests shall be conducted with gas at a pressure not less than P_a, 48.3 psig, at intervals no greater than 24 months except for tests involving:

1) Air locks,

2) Containment ventilation isolation valves with resilient material seals,

3) Safety injection valves as specified in Specification 4.6.1.2g, and

4) Containment spray valves as specified in Specification 4.6.1.2h.

e. Air locks shall be tested and demonstrated OPERABLE by the requirements of Specification 4.6.1.3;

f. Containment ventilation isolation valves with resilient material seals shall be tested and demonstrated OPERABLE by the requirements of Specification 4.6.1.7.2 or 4.6.1.7.3, as applicable;

g. Safety injection valves 1-8809A, 1-8809B, and 1-8840 shall be leak tested with a gas at a pressure not less than P_a, 48.3 psig, or with water at a pressure not less than 1.1 P_a, at intervals no greater than 24 months;

h. Containment spray valves 1HV-4776, 1HV-4777, 1CT-142, and 1CT-145 shall be leak tested with water at a pressure not less than 1.1 P_a, at intervals no greater than 24 months; and

i. The provisions of Specification 4.0.2 are not applicable.

3/4.6.1 PRIMARY CONTAINMENT

3/4.6.1.1 CONTAINMENT INTEGRITY

Primary CONTAINMENT INTEGRITY ensures that the release of radioactive materials from the containment atmosphere will be restricted to those leakage paths and associated leak rates assumed in the safety analyses. This restriction, in conjunction with the leakage rate limitation, will limit the EXCLUSION AREA BOUNDARY radiation doses to within the dose guideline values of 10 CFR 100 during accident conditions.

3/4.6.1.2 CONTAINMENT LEAKAGE

The limitations on containment leakage rates ensure that the total containment leakage volume will not exceed the value assumed in the safety analyses at the peak accident pressure, P_a. As an added conservatism, the measured overall integrated leakage rate is further limited to less than or equal to 0.75 L_a ~~or 0.75 L_t, as applicable~~ during performance of the periodic test to account for possible degradation of the containment leakage barriers between leakage tests.

For specific system configurations, credit may be taken for a 30-day water seal that will be maintained to prevent containment atmosphere leakage through the penetrations to the environment. The following is a list of the containment isolation valves that meet this system configuration and the Maximum Allowed Leakage Rate (MALR) required to maintain the water seal for 30 days.

Valve No.	MALR (cc/hr)
1-8809A	77
1-8809B	77
1-8840	2577
1CT-142	4734
1CT-145	4734
1HV-4776	4734
1HV-4777	4734

The surveillance testing for measuring leakage rates is consistent with the requirements of 10 CFR 50 Appendix J.

3/4.6.1.3 CONTAINMENT AIR LOCKS

The limitations on closure and leak rate for the containment air locks are required to meet the restrictions on CONTAINMENT INTEGRITY and containment leak rate. Surveillance testing of the air lock seals provides assurance that the overall air lock leakage will not become excessive due to seal damage during the intervals between air lock leakage tests.

ATTACHMENT 6 TO TXX-92410

DNBR SAFETY LIMIT

CONTENTS:

DESCRIPTION AND ASSESSMENT FOR LDCRs

I. BACKGROUND

Presently, the Comanche Peak Steam Electric Station (CPSES) Technical Specifications have Safety Limits and Limiting Conditions for Operations which are written to apply only to CPSES Unit 1 operation. The purpose of this change is to revise those DNBR related specifications necessary for the CPSES Technical Specifications to be applicable to both CPSES Unit 1 and Unit 2.

The designs of the reactor cores at CPSES were done with different DNB correlations and analysis methodologies. The Unit 1 core was designed using the W-3 DNB correlation and the Westinghouse Standard Thermal Design Procedure (STDP). Unit 2 was designed using the WRB-1 DNB correlation and the Westinghouse Improved Thermal Design Procedure (ITDP). These differences result in a DNBR safety analysis limit value of 1.49 for Unit 2 and 1.30 for Unit 1.

II. DESCRIPTION OF TECHNICAL SPECIFICATION CHANGE REQUEST

The proposed change encompasses several editorial and clarification items which are needed in order for the CPSES Unit 1 Technical Specifications to be applicable to both CPSES Units 1 and 2. The change identifies the necessary differences resulting from the different analyses of the two units. Unit 1 analysis was done utilizing the Standard Thermal Design Procedure (STDP), while Unit 2 employed the Improved Thermal Design Procedure (ITDP). Additionally, several setpoints are different for Unit 2 as a result of various design differences between the two units. Also, a correction in accordance with 10 CFR 50.4, changes an addressee of the monthly operating report.

The change to page iii adds a Unit 2 reactor core safety limit figure and makes necessary changes to the title of the Unit 1 figure. The actual changes are to change "Figure 2.1-1 Reactor Core Safety Limit" to "Figure 2.1-1a Unit 1 Reactor Core Safety Limit" and to add "Figure 2.1-1b Unit 2 Reactor Core Safety Limit." The change is consistent with those being proposed on pages 2-2 and 2-2a.

The change to page 2-2, revises the figure number from 2.1-1 to 2.1-1a and adds the unit designator to the figure title, "Unit 1" Reactor Core Safety Limit. This change is consistent with the addition of the Unit 2 Reactor Core Safety Limit figure. The change is needed due to the use of the WRB-1 DNB correlation and the ITDP for the design of Unit 2 as opposed to the W-3 DNB correlation and the STDP which is utilized for the design of the Unit 1 reactor core.

Page 2-2a is added to include "Figure 2.1-1b Unit 2 Reactor Core Safety Limit" as described in the previous paragraph.

There are numerous changes to page B 2-1, B 2-4, B 3/4 2-1, B 3/4 4-1 and B 3/4 2-8. These changes are included to make the BASES applicable to both CPSES Units 1 and 2. The two units at CPSES employ different DNB correlations and Thermal Design Procedures as well as having different nuclear enthalpy rise hot channel factor multipliers. Specific values or discussions related to these items which only relate to Unit 1 are being replaced with discussions that apply to both Units 1 and 2. The specific values for each unit will be included in the Core Operating Limits Reports as necessary.

The changes to pages 3/4 2-12 and B 3/4 2-6 add the allowable Unit 2 DNB related parameters (Tavg, Pressurizer Pressure, and Reactor Coolant System Flow) and their associated BASES. These changes result from the differences in the correlations used in the design of the two CPSES reactor cores.

The change to page B 3/4 2-4 provides the applicable margins in the safety analysis that offset rod bow penalties for Unit 2.

The change to pages 6-19 and 6-20 replaces the addressee of the monthly operating reports in agreement with 10 CFR 50.4, in particular "to the Director, Office of Resource Management, U. S. Nuclear Regulatory Commission," with " to the U.S. Nuclear Regulatory Commission, Document Control Desk."

Pages 6-20 and 6-20a are also changed to add the references which contain approved analytical methods to determine Unit 2 core operating limits and the sections are revised to clarify which references apply to Unit 1 and which references apply to Unit 2.

III. ANALYSIS

These changes update the Technical Specifications to reflect the DNB methodologies and thermal design procedures used on Unit 2, including related topics such as nuclear enthalpy rise hot channel factor multipliers and affected plant parameters such as Tavg, Pressurizer Pressure, and Reactor Coolant System Flow. Unit 2 rod bow penalties are addressed and the references for the Unit 2 core operating limits determination are added to Section 6.

IV. SIGNIFICANT HAZARDS CONSIDERATION DETERMINATION

Does the proposed change:

a) Involve a significant increase in the probability or consequences of an accident previously evaluated?

The changes do not impact any of the Unit 1 accident scenarios as the changes are for the inclusion of Unit 2. As the Unit 1 accident scenarios are not impacted there is no increase in the consequences of any previously evaluated accident.

The proposed change also involves administrative changes in reporting requirements for the Monthly Operating report. This change does not impact nor affect the accident analysis assumptions. Therefore, these assumptions are preserved and there is no change in the probability or consequences of any previously evaluated accident.

b) Create the possibility of a new or different kind of accident from any accident previously evaluated?

This change does not create the possibility of a new or different kind of accident for CPSES Unit 1. The change is adding Unit 2 information.

c) Involve a significant reduction in the margin of safety, as defined by the bases of CPSES Unit 1 Technical Specifications?

The changes provides for the inclusion of the Unit 2 DNBR and has no impact on the margin of safety. Therefore, there is no significant reduction in the margin of safety as defined by the basis of the CPSES Unit 1 Technical Specifications.

Based on the above evaluations, TU Electric concludes that the activity associated with the above described change presents no significant hazards consideration under the standards set out in 10 CFR 50.92(c) and, accordingly, a finding by the NRC of no significant hazards consideration is justified.

V. ENVIRONMENTAL EVALUATION

TU Electric has evaluated the proposed change and has determined that the change does not involve (i) a significant hazards consideration, (ii) a significant change in the types or significant increase in the amounts of any effluents that may be released offsite, or (iii) a significant increase in individual or cumulative occupational radiation exposure. Accordingly, the proposed change meets the eligibility criterion for categorical exclusion set forth in 10 CFR 51.22(c)(9); therefore, pursuant to 10 CFR 51.22(b), an environmental assessment of the proposed change is not required.

INDEX

SAFETY LIMITS AND LIMITING SAFETY SYSTEM SETTINGS

BASES

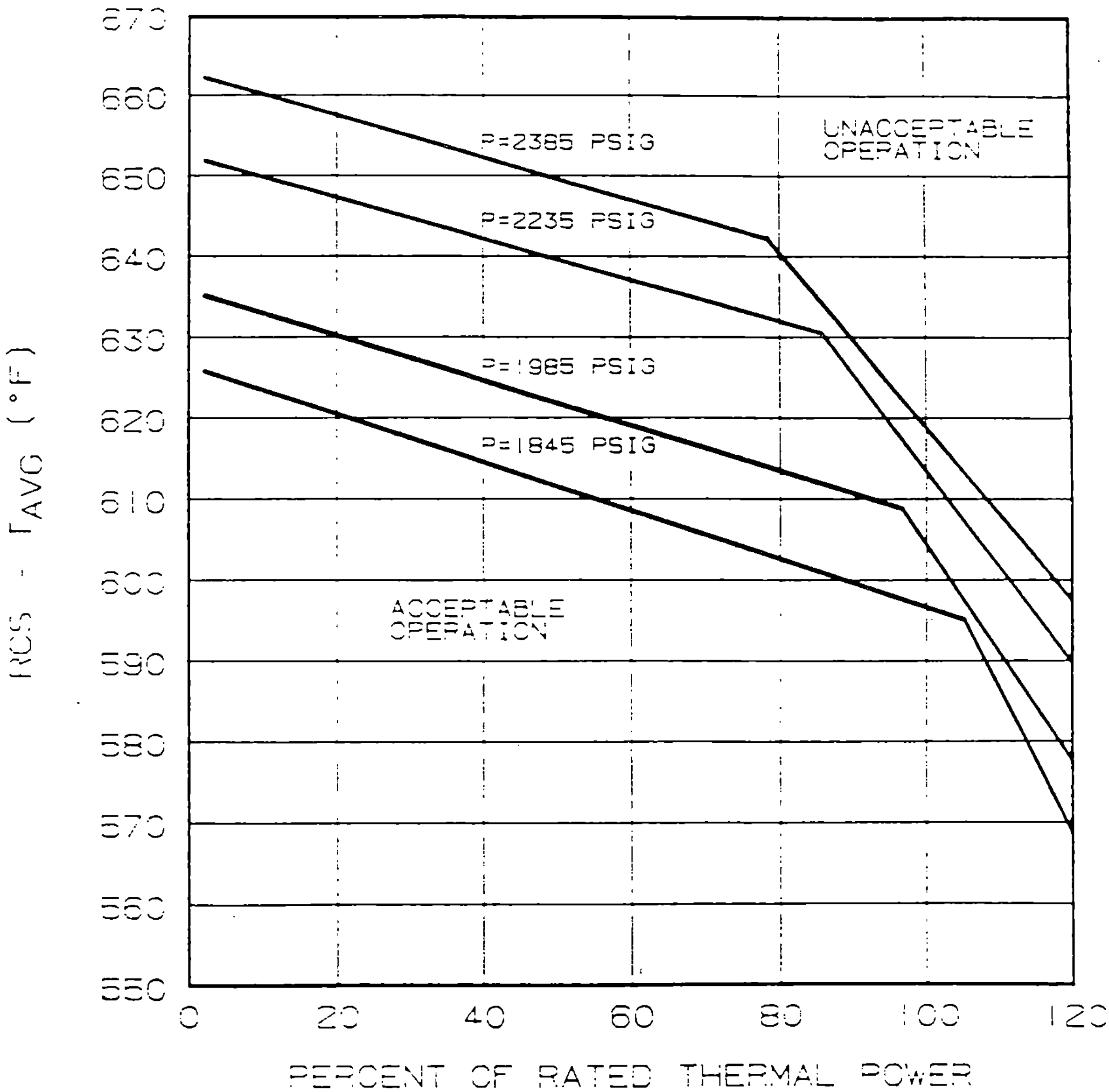

FIGURE 2.1-1a

UNIT 1 REACTOR CORE SAFETY LIMITS

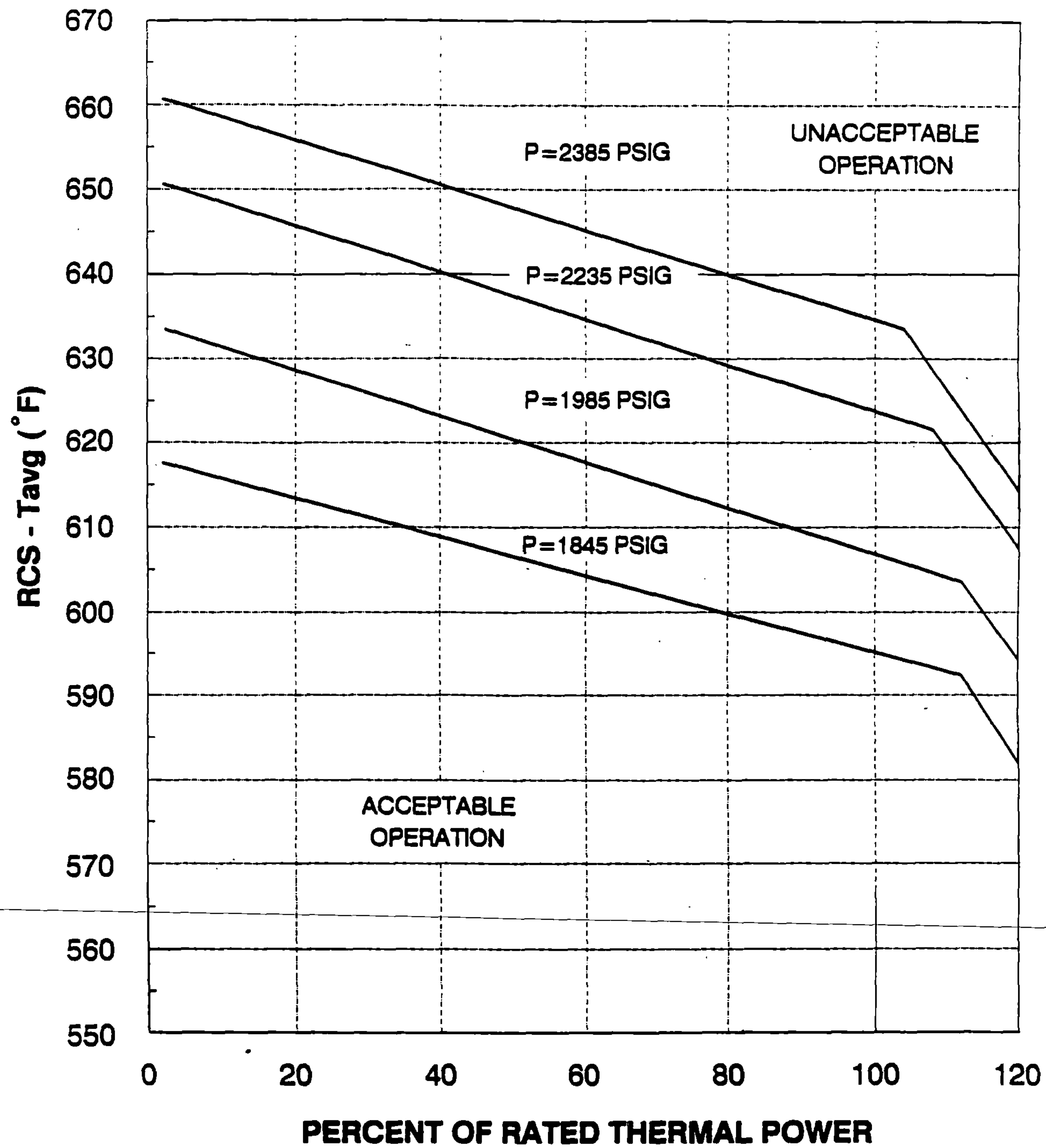

FIGURE 2.1-1 b

UNIT 2 **REACTOR CORE SAFETY LIMITS**

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.

INSERT 1

~~The local DNB heat flux ratio (DNBR) is defined as the ratio of the heat flux that would cause DNB at a particular core location to the local heat flux and is indicative of the margin to DNB. DNBR is not a directly measurable parameter during operation and therefore THERMAL POWER and reactor coolant temperature and pressure have been related to DNBR through the W-3 correlation. The W-3 DNB correlation has been developed to predict the DNB flux and the location of DNB for axially uniform and nonuniform heat flux distributions.~~

~~The minimum value of the DNBR during steady-state operation, normal operational transients, and anticipated transients is limited to 1.30. This value corresponds to a 95% probability at a 95% confidence level that DNB will not occur and is chosen as an appropriate margin to DNB for all operating conditions.~~

The curves of Figure 2.1-1 show the loci of points of THERMAL POWER, Reactor Coolant System pressure and average temperature ~~for which the minimum DNBR is no less than 1.30~~ below which the calculated DNBR is no less than the Safety analysis limit value, or the average enthalpy at the vessel exit is ~~equal to~~ less than the enthalpy of saturated liquid.

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

INSERT 2

~~$F^N_{\Delta H} = 1.55\ [1 + 0.2\ (1-P)]$,~~

~~Where P is the fraction of RATED THERMAL POWER.~~

These limiting heat flux conditions are ~~more limiting~~ higher than those calculated for the range of all control rods fully withdrawn to the maximum allowable control rod insertion assuming the axial power imbalance is within the limits of the f_1 (ΔI) function of the Overtemperature N-16 trip. When the axial power imbalance is not within the tolerance, the axial power imbalance effect on the Overtemperature N-16 trips will reduce the Setpoints to provide protection consistent with core Safety Limits.

INSERTS for Page B 2-1

INSERT 1

DNB is not a directly measureable 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 heat flux and the location of DNB for axially uniform and non-uniform heat flux distributions. The local 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 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 level that DNB will not occur when the minimum DNBR is at the DNBR limit. In meeting this design basis, uncertainties in plant operating parameters are considered such that the minimum DNBR for the limiting rod is greater than or equal to the DNBR limit. In addition, margin has been maintained in the design by meeting safety analysis DNBR limits in performing safety analyses.

INSERT 2

$$F^{N}_{\Delta H} = F^{RTP}_{\Delta H}\,[1 + P^{F}_{\Delta H}\,(1-P)],$$

Where: P = the fraction of RATED THERMAL POWER (RTP).

$F^{RTP}_{\Delta H}$ = the $F^{N}_{\Delta H}$ limit at RTP specified in the CORE OPERATING LIMITS REPORT (COLR), and

$P^{F}_{\Delta H}$ = the power factor multiplier for $F^{N}_{\Delta H}$ specified in the COLR.

REACTOR TRIP SYSTEM INSTRUMENTATION SETPOINTS (Continued)

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

Manual Reactor Trip

The Reactor Trip System includes manual Reactor trip capability.

Power Range, Neutron Flux

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

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

Power Range, Neutron Flux, High Rates

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

The Power Range Negative Rate trip provides protection for control rod drop accidents. At high power a single or multiple rod drop accident could cause local flux peaking which could cause an unconservative local DNBR to exist. The Power Range Negative Rate trip will prevent this from occurring by tripping the reactor. No credit is taken for operation of the Power Range Negative Rate trip for those control rod drop accidents for which DNBRs will be greater than ~~1.30.~~ the DNBR safety analysis limit.

3/4.2 POWER DISTRIBUTION LIMITS

BASES

the safety analysis limit value

The specifications of this section provide assurance of fuel integrity during Condition I (Normal Operation) and II (Incidents of Moderate Frequency) events by: (1) maintaining the minimum DNBR in the core greater than or equal to ~~1.30~~ during normal operation and in short-term transients, and (2) limiting the fission gas release, fuel pellet temperature, and cladding mechanical properties to within assumed design criteria. In addition, limiting the peak linear power density during Condition I events provides assurance that the initial conditions assumed for the LOCA analyses are met and the ECCS acceptance criteria limit of 2200°F is not exceeded.

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

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

$F^N_{\Delta H}$ Nuclear Enthalpy Rise Hot Channel Factor, is defined as the ratio of the integral of linear power along the rod with the highest integrated power to the average rod power.

3/4.2.1 AXIAL FLUX DIFFERENCE

The limits on AXIAL FLUX DIFFERENCE (AFD) assure that the $F_Q(Z)$ upper bound envelope of the F_Q limit specified in the CORE OPERATING LIMITS REPORT (COLR) times the normalized axial peaking factor is not exceeded during either normal operation or in the event of xenon redistribution following power changes.

Target flux difference is determined at equilibrium xenon conditions. The rods may be positioned within the core in accordance with their respective insertion limits and should be inserted near their normal position for steady-state operation at high power levels. The value of the target flux difference obtained under these conditions divided by the fraction of RATED THERMAL POWER is the target flux difference at RATED THERMAL POWER for the associated core burnup conditions. Target flux differences for other THERMAL POWER levels are obtained by multiplying the RATED THERMAL POWER value by the appropriate fractional THERMAL POWER level. The periodic updating of the target flux difference value is necessary to reflect core burnup considerations.

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

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

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

$F^N_{\Delta H}$ will be maintained within its limits provided Conditions a. through d. above are maintained. The relaxation of $F^N_{\Delta H}$ as a function of THERMAL POWER allows changes in the radial power shape for all permissible rod insertion limits.

INSERT 3

Fuel rod bowing reduces the value of the DNB ratio. Credit is available to offset this reduction in the generic margin. The generic margin~~s~~, totaling 9.1% DNBR completely offset any rod bow penalties. This margin includes the following for Unit 1:

a. Design limit DNBR of 1.30 vs 1.28,

b. Grid Spacing (K_s) of 0.046 vs 0.059,

c. Thermal Diffusion Coefficient of 0.038 vs 0.051,

d. DNBR Multiplier of 0.86 vs 0.88, and

e. Pitch reduction.

INSERT 4

The applicable values of rod bow penalties are referenced in the FSAR.

When an F_Q measurement is taken, an allowance for both experimental error and manufacturing tolerance must be made. An allowance of 5% is appropriate for a full-core map taken with the Incore Detector Flux Mapping System, and a 3% allowance is appropriate for manufacturing tolerance.

When $F^N_{\Delta H}$ is measured, an adjustment for measurement uncertainty must be included for a full-core flux map taken with the Incore Detector Flux Mapping System.

The Radial Peaking Factor, $F_{xy}(Z)$, is measured periodically to provide assurance that the Hot Channel Factor, $F_Q(Z)$, remains within its limit. The F_{xy} limit for RATED THERMAL POWER (F_{xy}^{RTP}) as provided in the Radial Peaking Factor Limit Report per Specification 6.9.1.6 was determined from expected power control manuevers over the full range of burnup conditions in the core.

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INSERT 3

for Unit 1 and 10.1% for typical cells and 9.5% for thimble cells for Unit 2 for

INSERT 4

The margin for Unit 2 is included by establishing a fixed difference between the safety analysis limit DNBR and the design limit DNBR equal to the percent margin of the safety analysis limit DNBR.

BASES

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 ~~of 1.30~~ at or above the safety analysis limit value throughout each analyzed transient. The Unit 1 indicated T_{avg} value of 592.7°F (conservatively rounded to 592°F) and the Unit 1 indicated pressurizer pressure value of 2207 psig correspond to analytical limits of 594.7°F and 2193 psig respectively, with allowance for measurement uncertainty. The Unit 2 indicated T_{avg} value of 592.8°F (conservatively rounded to 592°F) and the Unit 2 indicated pressurizer pressure value of 2219 psig correspond to analytical limits of 595.16°F and 2205 psig respectively, with allowance for measurement uncertainty. The indicated uncertainties assume that the reading from four channels will be averaged before comparing with the required limit.

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, and to detect any significant flow degradation of the Reactor Coolant System (RCS).

The additional surveillance requirements associated with the RCS total flow rate are sufficient to ensure that the measurement uncertainties are limited to 1.8% as assumed in the Improved Thermal Design Procedure Report for CPSES.

Performance of a precision secondary calorimetric is required to precisely determine the RCS temperature. The transit time flow meter, which uses the N-16 system signals, is then used to accurately measure the RCS flow. Subsequently, the RCS flow detectors (elbow tap differential pressure detectors) are normalized to this flow determination and used throughout the cycle.

POWER DISTRIBUTION LIMITS

3/4.2.5 DNB PARAMETERS

LIMITING CONDITION FOR OPERATION

3.2.5 The following DNB-related parameters shall be maintained within the stated limits:

a. Indicated Reactor Coolant System $T_{avg} \leq 592°F$

b. Indicated Pressurizer Pressure $\geq$ 2207 psig* for Unit 1
$\geq$ 2219 psig* for Unit 2

c. Indicated Reactor Coolant System (RCS) Flow $\geq$ 389,700 gpm** for Unit 1
$\geq$ 395,200 gpm** for Unit 2

APPLICABILITY: MODE 1.

ACTION:

With any of the above parameters exceeding its limit, restore the parameter to within its limit within 2 hours or reduce THERMAL POWER to less than 5% of RATED THERMAL POWER within the next 4 hours.

SURVEILLANCE REQUIREMENTS

4.2.5.1 Each of the above parameters shall be verified to be within its limits at least once per 12 hours.

4.2.5.2 The RCS total flow rate shall be verified to be within its limits at least once per 31 days by plant computer indication or measurement of the RCS elbow tap differential pressure transmitters' output voltage.

4.2.5.3 The RCS loop flow rate indicators shall be subjected to a CHANNEL CALIBRATION at least once per 18 months. The channels shall be normalized based on the RCS flow rate determination of Surveillance Requirement 4.2.5.4.

4.2.5.4 The RCS total flow rate shall be determined by precision heat balance measurement after each fuel loading and prior to operation above 75% of RATED THERMAL POWER. The feedwater pressure and temperature, the main steam pressure, and feedwater flow differential pressure instruments shall be calibrated within 90 days of performing the calorimetric flow measurement.

*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.

**Includes a 1.8% flow measurement uncertainty.

3/4.4.1 REACTOR COOLANT LOOPS AND COOLANT CIRCULATION

to the

The plant is designed to operate with all reactor coolant loops in operation and maintain DNBR ~~above 1.30~~ during all normal operations and anticipated transients. In MODES 1 and 2 with one reactor coolant loop not in operation this specification requires that the plant be in at least HOT STANDBY within 6 hours. greater than or equal to the safety analysis limit value

In MODE 3, two reactor coolant loops provide sufficient heat removal capability for removing core decay heat, even in the event of a bank withdrawal accident; however, a single reactor coolant loop provides sufficient heat removal capacity if a bank withdrawal accident can be prevented, i.e., by opening the Reactor Trip System breakers. Single failure considerations require that two loops be OPERABLE at all times.

In MODES 3, 4, and 5, the operability of the required steam generators is based on maintaining a sufficient level to guarantee tube coverage to assure heat transfer capability.

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

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

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

The restrictions on starting an RCP with one or more RCS cold legs less than or equal to 350°F are provided to prevent RCS pressure transients, caused by energy additions from the Secondary Coolant System, which could exceed the limits of 10 CFR 50 Appendix G. The RCS will be protected against overpressure transients and will not exceed the limits of Appendix G by restricting starting of the RCPs to when the secondary water temperature of each steam generator is less than 50° above each of the RCS cold leg temperatures.

3/4.4.2 SAFETY VALVES

The pressurizer Code safety valves operate to prevent the RCS from being pressurized above its Safety Limit of 2735 psig. Each safety valve is designed to relieve 420,000 lbs per hour of saturated steam at the valve Setpoint. In the event that no safety valves are OPERABLE, an operating RHR loop, connected to the RCS, provides overpressure relief capability and will prevent RCS overpressurization.

CORE OPERATING LIMITS REPORT (Continued)

5. WCAP-10216-P-A, "RELAXATION OF CONSTANT AXIAL OFFSET CONTROL FQ SURVEILLANCE TECHNICAL SPECIFICATION," June 1983 (W Proprietary). (Methodology for Specification 3.2.2 - Heat Flux Hot Channel Factor (W (z) surveillance requirements for F_Q Methodology).)

References 6. and 7. are for Unit 1 only:

6. WCAP-8200, "WFLASH, A FORTRAN-IV COMPUTER PROGRAM FOR SIMULATION OF TRANSIENTS IN A MULTI-LOOP PWR," Revision 2, July 1974 (W Proprietary). (Methodology for Specification 3.2.2. - Heat Flux Hot Channel Factor.)

7. WCAP-9220-P-A, "Westinghouse ECCS Evaluation Model, February 1978 Version," February 1978 (W Proprietary). (Methodology for Specification 3.2.2. - Heat Flux Hot Channel Factor.)

INSERT 5

6.9.1.6c The core operating limits shall be determined so that all applicable limits (e.g., fuel thermal-mechanical limits, core thermal-hydraulic limits, ECCS limits, nuclear limits such as shutdown margin, and transient and accident analysis limits) of the safety analysis are met.

6.9.1.6d The CORE OPERATING LIMITS REPORT, including any mid-cycle revisions or supplements thereto, shall be provided upon issuance, for each reload cycle, to the NRC Document Control Desk with copies to the Regional Administrator and Resident Inspector.

SPECIAL REPORTS

6.9.2 In addition to the applicable reporting requirements of Title 10, Code of Federal Regulations, special reports shall be submitted to the Regional Administrator of the Regional Office of the NRC within the time period specified for each report.

6.10 RECORD RETENTION

6.10.1 In addition to the applicable record retention requirements of Title 10, Code of Federal Regulations, the following records shall be retained for at least the minimum period indicated.

6.10.2 The following records shall be retained for at least 5 years:

a. Records and logs of unit operation covering time interval at each power level;

b. Records and logs of principal maintenance activities, inspections, repair, and replacement of principal items of equipment related to nuclear safety;

INSERT 5 for Page 6-20a

References 8, 9, 10 and 11 are for Unit 2 only:

8. WCAP-9220-P-A, Rev. 1, "WESTINGHOUSE ECCS EVALUATION MODEL-1981 VERSION", February 1982 (W Proprietary). (Methodology for Specification 3.2.2 - Heat Flux Hot Channel Factor.)

9. WCAP-10079-P-A, " NOTRUMP, A NODAL TRANSIENT SMALL BREAK AND GENERAL NETWORK CODE," August 1985, (W Proprietary). (Methodology ;for Specification 3.2.2 - Heat Flux Hot Channel Factor.)

10. WCAP-10054-P-A, "WESTINGHOUSE SMALL BREAK ECCS EVALUATION MODEL USING THE NOTRUMP CODE", August 1985, (W Proprietary). (Methodology for Specification 3.2.2 - Heat Flux Hot Channel Factor).

11. WCAP-11145-P-A, "WESTINGHOUSE SMALL BREAK LOCA ECCS EVALUATION MODEL GENERIC STUDY WITH THE NOTRUMP CODE", October 1986, (W Proprietary). (Methodology for Specification 3.2.2 - Heat Flux Hot Channel Factor).