TENNESSEE VALLEY AUTHORITY
CHATTANOOGA, TENNESSEE 37401
400 Chestnut Street Tower II

January 30, 1985

Director of Nuclear Reactor Regulation
Attention: Ms. E. Adensam, Chief
Licensing Branch No. 4
Division of Licensing
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

Dear Ms. Adensam:

In the Matter of the Application of	)	Docket Nos. 50-390
Tennessee Valley Authority	)	50-391

Please refer to Thomas M. Novak's letter to H. G. Parris dated December 11, 1984 which transmitted the final draft version of the Watts Bar Nuclear Plant (WBN) unit 1 Appendix A Technical Specifications.

TVA's review of the final draft version of the WBN unit 1 Technical Specifications is near completion. Enclosed are our proposed modifications as of to date. Additional proposed changes will be forwarded in the near future.

Please note that many of the proposed modifications included in the enclosure have been previously transmitted to the staff but have yet to be satisfactorily resolved. Also, in addition to the enclosed proposed changes, several of the more significant issues are presently being discussed between TVA and NRC staff management.

If you have any questions concerning this matter, please get in touch with D. B. Ellis at FTS 858-2681.

Very truly yours,

TENNESSEE VALLEY AUTHORITY

D. L. Lambert

D. L. Lambert
Nuclear Engineer

Sworn to and subscribed before me
this 30th day of Jan., 1985

Paulette H. White
Notary Public
My Commission Expires 8-24-88

Enclosure
cc: U.S. Nuclear Regulatory Commission (Enclosure)
Region II
Attn: Mr. James P. O'Reilly Administrator
101 Marietta Street, NW, Suite 2900
Atlanta, Georgia 30323

Limited Distribution

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TABLE 2.2-1 (Continued)

TABLE NOTATIONS (Continued)

NOTE 1: (continued)

τ_6	=	Time constant utilized in the measured T_{avg} lag compensator, τ_6 = 2 s,
T'	$\leq$	588.2°F (Nominal T_{avg} allowed by Safety Analysis ~~at RATED THERMAL POWER~~),
K_3	=	0.000647/psig,
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 detectors of the power range neutron ion chambers; with gains to be selected based on measured instrument response during plant startup tests such that:

(i) for $q_t - q_b$ between -32% and +10% $f_1(\Delta I) = 0$ (where q_t and q_b are percent RATED THERMAL POWER in the top and bottom halves of the core respectively, and $q_t + q_b$ is total THERMAL POWER in percent of RATED THERMAL POWER);

(ii) for each percent that the magnitude of $(q_t - q_b)$ is more negative than ~~exceeds~~ -32%, the ΔT Trip Setpoint shall be automatically reduced by 1.34% of its value at RATED THERMAL POWER;

(iii) for each percent that the magnitude of $(q_t - q_b)$ is more positive than ~~exceeds~~ +10%, the ΔT Trip Setpoint shall be automatically reduced by 1.22% of its value at RATED THERMAL POWER.

NOTE 2: The channel's maximum Trip Setpoint shall not exceed its computed Trip Setpoint by more than 3.1%.

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3/4.4.4 RELIEF VALVES

The power-operated relief valves (PORVs) and steam bubble function to relieve RCS pressure during all design transients up to and including the design step load decrease with steam dump. Operation of the PORVs minimizes the undesirable opening of the spring-loaded pressurizer Code safety valves. Each PORV has a remotely operated block valve to provide a positive shutoff capability should a relief valve become inoperable.

3/4.4.5 STEAM GENERATORS

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

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

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

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3/4.10.2 GROUP HEIGHT, INSERTION, AND POWER DISTRIBUTION LIMITS

LIMITING CONDITION FOR OPERATION

3.10.2 The group height, insertion, and power distribution limits of Specifications 3.1.3.1, 3.1.3.5, 3.1.3.6, ~~3.2.1~~, and 3.2.4 may be suspended during the performance of PHYSICS TESTS provided:

a. The THERMAL POWER is maintained less than or equal to 85% of RATED THERMAL POWER, and

b. The limits of Specifications 3.2.2 and 3.2.3 are maintained and determined at the frequencies specified in Specification 4.10.2.2 below.

APPLICABILITY: MODE 1.

ACTION:

With any of the limits of Specifications 3.2.2 or 3.2.3 being exceeded while the requirements of Specifications 3.1.3.1, 3.1.3.5, 3.1.3.6, ~~3.2.1~~, and 3.2.4 are suspended, either:

a. Reduce THERMAL POWER sufficient to satisfy the ACTION requirements of Specifications 3.2.2 and 3.2.3, or

b. Be in HOT STANDBY within 6 hours.

SURVEILLANCE REQUIREMENTS

4.10.2.1 The THERMAL POWER shall be determined to be less than or equal to 85% of RATED THERMAL POWER at least once per hour during PHYSICS TESTS.

4.10.2.2 The requirements of the below listed specfications shall be performed at least once per 12 hours during PHYSICS TESTS:

a. Specifications 4.2.2.2 and 4.2.2.3, and

b. Specification 4.2.3.2.

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LIMITING CONDITION FOR OPERATION

3.4.9.3 At least one of the following Overpressure Protection Systems shall be OPERABLE:

a. Two power operated relief valves (PORVs) with setpoints which do not exceed the limit established by ~~a nominal lift setting as shown in~~ Figure 3.4-4, or

b. The Reactor Coolant System (RCS) depressurized with an RCS vent of greater than or equal to 3 square inches.

APPLICABILITY: MODE 4 when the temperature of any RCS cold leg is less than or equal to 310°F, MODE 5 and MODE 6 with the reactor vessel head on.

ACTION:

a. With one PORV inoperable, restore the inoperable PORV to OPERABLE status within 7 days or depressurize and vent the RCS through at least a 3 square inch vent within the next 8 hours.

b. With both PORVs inoperable, depressurize and vent the RCS through at least a 3 square inch vent within 8 hours.

c. In the event either the PORVs or the RCS vent(s) are used to mitigate an RCS pressure transient, a Special Report shall be prepared and submitted to the Commission pursuant to Specification 6.9.2 within 30 days. The report shall describe the circumstances initiating the transient, the effect of the PORVs or RCS vent(s) on the transient, and any corrective action necessary to prevent recurrence.

d. The provisions of Specification 3.0.4 are not applicable.

TABLE 4.4-5

REACTOR VESSEL MATERIAL SURVEILLANCE PROGRAM - WITHDRAWAL SCHEDULE

CAPSULE NUMBER	VESSEL LOCATION	LEAD FACTOR	WITHDRAWAL TIME (EFPY)
U	56°	4.8	1st Refueling
X	236°	4.8	~~6~~ 4
V	58.5°	4.0	8
Y	238.5°	4.0	15
W	124°	4.8	STBY
Z	304°	4.8	STBY

TABLE 4.4-2

STEAM GENERATOR TUBE INSPECTION

1ST SAMPLE INSPECTION			2ND SAMPLE INSPECTION		3RD SAMPLE INSPECTION	
Sample Size	Result	Action Required	Result	Action Required	Result	Action Required
A minimum of S Tubes per S. G.	C–1	None	N. A.	N. A.	N. A.	N. A.
	C–2	Plug or repair defective tubes and inspect additional 2S tubes in this S. G.	C–1	None	N. A.	N. A.
			C–2	Plug or repair defective tubes and inspect additional 4S tubes in this S. G.	C–1	None
					C–2	Plug or repair defective tubes
					C–3	Perform action for C–3 result of first sample
			C–3	Perform action for C–3 result of first sample	N. A.	N. A.
	C–3	Inspect all tubes in this S. G., plug or repair defective tubes and inspect 2S tubes in each other S. G. Notification to NRC pursuant to §50.72 (b)(2) of 10 CFR Part 50	All other S. G.s are C–1	None	N. A.	N. A.
			Some S. G.s C–2 but no additional S. G. are C–3	Perform action for C–2 result of second sample	N. A.	N. A.
			Additional S. G. is C–3	Inspect all tubes in each S. G. and plug or repair defective tubes. Notification to NRC pursuant to §50.72 (b)(2) of 10 CFR Part 50	N. A.	N. A.

$S = 3 \frac{N}{n} \%$ Where N is the number of steam generators in the unit, and n is the number of steam generators inspected during an inspection

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SURVEILLANCE REQUIREMENTS (Continued)

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

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

4.4.5.5 Reports

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

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

1) Number and extent of tubes inspected,

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

3) Identification of tubes plugged or repaired

c. Results of steam generator tube inspections, which fall into Category C-3, shall be reported in a Special Report to the Commission pursuant to Specification 6.9.2 within 30 days and prior to resumption of plant operation. This report shall provide a description of investigations conducted to determine cause of the tube degradation and corrective measures taken to prevent recurrence.

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SURVEILLANCE REQUIREMENTS (Continued)

4.4.5.4 Acceptance Criteria

a. As used in this specification:

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

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

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

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

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

6) Plugging Limit means the imperfection depth at or beyond which the tube shall be removed from service or repaired by an acceptable methods such as sleeving. ~~and~~ It is equal to 40% of the nominal tube wall thickness.

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

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

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SURVEILLANCE REQUIREMENTS (Continued)

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

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

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

not less than 12 or more than 24 months.

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

1) Reactor-to-secondary tubes leaks (not including leaks originating from tube-to-tube sheet welds) in excess of the limits of Specification 3.4.6.2, or

2) A seismic occurrence greater than the Operating Basis Earthquake, or

3) A loss-of-coolant accident requiring actuation of the Engineered Safety Features, or

4) A main steam line or feedwater line break.

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MOVABLE INCORE DETECTORS

LIMITING CONDITION FOR OPERATION

3.3.3.2 The Movable Incore Detection System shall be OPERABLE with:

a. At least 75% of the detector thimbles,

b. A minimum of two detector thimbles per core quadrant, and

c. Sufficient movable detectors, drive, and readout equipment to map these thimbles.

APPLICABILITY: When the movable incore detection system is used for:

a. Recalibration of the Excore Neutron Flux Detection System, or

b. Monitoring the QUADRANT POWER TILT RATIO, or

c. Measurement of $F^N_{\Delta H}$, $F_Q(Z)$ and F_{xy}.

ACTION:

a. With the Movable Incore Detection System inoperable, do not use the system for the above applicable monitoring or calibration functions.

b. The provisions of Specifications 3.0.3 and 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.3.3.2 The Movable Incore Detection System shall be demonstrated OPERABLE at least once per 24 hours by ~~normalizing each detector output when required for:~~ irradiating each detector USED and determining the acceptability of its voltage curve for:

a. Recalibration of the Excore Neutron Flux Detection System, or

b. Monitoring the QUADRANT POWER TILT RATIO, or

c. Measurement of $F^N_{\Delta H}$, $F_Q(Z)$, and F_{xy}.

TABLE 3.3-10

ACCIDENT MONITORING INSTRUMENTATION

INSTRUMENT	TOTAL NO. OF CHANNELS	MINIMUM CHANNELS OPERABLE
1. Containment Pressure	2	1
2. Reactor Coolant Outlet Temperature - T_{HOT} (Wide Range)	2	1
3. Reactor Coolant Inlet Temperature - T_{COLD} (Wide Range)	2	1
4. Reactor Coolant Pressure - Wide Range	2	1
5. Pressurizer Water Level	2	1
6. Steam Line Pressure	2/steam ~~generator~~ line	1/steam ~~generator~~ line
7. Steam Generator Water Level - Narrow Range	1/steam generator	1/steam generator
8. Steam Generator Water Level - Wide Range	1/steam generator	1/steam generator
9. Refueling Water Storage Tank Water Level	2	1
10. Auxiliary Feedwater Flow Rate	2/steam generator	1/steam generator
11. Reactor Coolant System Subcooling Margin Monitor	2	1
12. PORV Position Indicator*	2/Valve	1/Valve
13. PORV Block Valve Position Indicator**	2/Valve	1/Valve
14. Safety Valve Position Indicator	2/Valve	1/Valve
15. Containment Sump Water Level	2	1
16. In Core Thermocouples	4/core quadrant	2/core quadrant
17. Essential Raw Cooling Water Flow	2	1

*Not applicable if the associated block valve is in the closed position.

**Not applicable if the block valve is verified closed with power to the valve operator removed.

TABLE 2.2-1

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
1. Manual Reactor Trip	N.A.	N.A.
2. Power Range, Neutron Flux		
a. Low Setpoint	≤ 25% of RATED THERMAL POWER	≤ 26% of RATED THERMAL POWER
b. High Setpoint	≤ 109% of RATED THERMAL POWER	≤ 110% of RATED THERMAL POWER
3. Power Range, Neutron Flux, High Positive Rate	≤ 5% of RATED THERMAL POWER with a time constant ≥ 2 seconds	≤ 5.5% of RATED THERMAL POWER with a time constant ≥ 2 seconds
4. Power Range, Neutron Flux, High Negative Rate	≤ 5% of RATED THERMAL POWER with a time constant ≥ 2 seconds	≤ 5.5% of RATED THERMAL POWER with a time constant ≥ 2 seconds
5. Intermediate Range, Neutron Flux	≤ 25% of RATED THERMAL POWER	≤ 30% of RATED THERMAL POWER
6. Source Range, Neutron Flux	≤ 10^5 cps 1.0×10^5 cps	≤ 1.5 x 10^5 cps
7. Overtemperature ΔT	See Note 1	See Note 2
8. Overpower ΔT	See Note 3	See Note 4
9. Pressurizer Pressure--Low	≥ 1970 psig	≥ 1950 psig
10. Pressurizer Pressure--High	≤ 2385 psig	≤ 2395 psig
11. Pressurizer Water Level--High	≤ 92% of instrument span	≤ 93% of instrument span
12. Reactor Coolant Flow-Low-Single Loop (Above P-8)	≥ 90% of design flow per loop*	≥ 89% of design flow per loop*
13. Reactor Coolant Flow-Low-Two Loops (Above P-7 and Below P-8)	≥ 90% of design flow per loop*	≥ 89% of design flow per loop*

*Design flow is 97,500 gpm per loop.

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TABLE 2.2-1 (Continued)

TABLE NOTATIONS

NOTE 1: OVERTEMPERATURE ΔT

$$\Delta T \left(\frac{1 + \tau_1 S}{1 + \tau_2 S}\right) \left(\frac{1}{1 + \tau_3 S}\right) \leq \Delta T_0 \left\{K_1 - K_2 \left(\frac{1 + \tau_4 S}{1 + \tau_5 S}\right) \left[T\left(\frac{1}{1 + \tau_6 S}\right) - T'\right] + K_3 (P - P') - f_1 (\Delta q)\right\}$$

Where:

ΔT	=	Measured ΔT by RTD Manifold Instrumentation,
$\frac{1 + \tau_1 S}{1 + \tau_2 S}$	=	Lead-lag compensator on measured ΔT,
τ_1, τ_2	=	Time constants utilized in the lead-lag compensator for ΔT, τ_1 = 8 s, τ_2 = 3s, space
$\frac{1}{1 + \tau_3 S}$	=	Lag compensator on measured ΔT,
τ_3	=	Time constant utilized in the lag compensator for ΔT, τ_3 = 2 s,
ΔT_0	=	Indicated ΔT at RATED THERMAL POWER,
K_1	=	1.0952,
K_2	=	0.0133/°F,
$\frac{1 + \tau_4 S}{1 + \tau_5 S}$	=	The function generated by the lead-lag compensator for T_{avg} dynamic compensation,
τ_4, τ_5	=	Time constants utilized in the lead-lag compensator for T_{avg}, τ_4 = 33 s, τ_5 = 4 s,
T	=	Average temperature, °F,
$\frac{1}{1 + \tau_6 S}$	=	Lag compensator on measured T_{avg},

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3/4 LIMITING CONDITIONS FOR OPERATION AND SURVEILLANCE REQUIREMENTS

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 res~~tored pri~~or to expiration of the specified time intervals, completion of the Action requirements is not required.

ACTION

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 unless the conditions for the Limiting Condition for Operation are met without reliance on provisions contained in the ACTION requirements. 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.

TABLE 3.3-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
12. Reactor Coolant Flow - Low - Single Loop (Above P-8)	3/loop	2/loop in any operating loop	2/loop in each operating loop	1	$7^{\#}$
13. Reactor Coolant Flow - Low - Two Loops (Above P-7 and below P-8)	3/loop	2/loop in two operating loops	2/loop each operating loop	1	$7^{\#}$
14. Steam Generator Water Level--Low-Low	3/stm. gen.	2/stm. gen. in any operating stm. gen.	2/stm. gen. each operating stm. gen.	1, 2	$7^{\#}$
15. Steam Generator Water Level - Low Coincident With Steam/Feedwater Flow Mismatch	2 stm. gen. level and 2 stm/feedwater flow mismatch in in each stm gen.	1 stm. gen. level coincident with 1 stm./feedwater flow mismatch in same stm gen.	1 stm. gen. level and 2 stm/feedwater flow mismatch in same stm gen. or 2 stm gen. level and 1 stm/feedwater flow mismatch in same steam gen.	1, 2	$7^{\#}$
16. Undervoltage-Reactor Coolant Pumps	4-1/bus	2	3	1	$6^{\#}$
17. Underfrequency-Reactor Coolant Pumps	4-1/bus	2	3	1	$6^{\#}$

TABLE 3.3-2 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION RESPONSE TIMES

FUNCTIONAL UNIT	RESPONSE TIME
12. Reactor Coolant Flow - Low - Single Loop (Above P-8)	$\leq$ 1 second
13. Reactor Coolant Flow - Low - Two Loops (Above P-7 and Below P-8)	$\leq$ 1 second
14. Steam Generator Water Level-Low-Low	$\leq$ 2 seconds
15. Steam Generator Water Level-Low Coincident with Steam/Feedwater Flow Mismatch	N.A.
16. Undervoltage-Reactor Coolant Pumps	$\leq$ 1.5 seconds
17. Underfrequency-Reactor Coolant Pumps	$\leq$ 0.6 second
18. Turbine Trip	
a. Low Fluid Oil Pressure	N.A.
b. Turbine Stop Valve Closure	N.A.
19. Safety Injection Input from ESF	N.A.
20. Reactor Trip System Interlocks	N.A.
21. Reactor Trip Breakers	N.A.
22. Automatic Trip and Interlock Logic	N.A.

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TABLE 3.3-3 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
3. Containment Isolation (Continued)					
c. Containment Ventilation Isolation					
1) Manual Initiation	2	1	2	1, 2, 3, 4	17
2) Automatic Actuation Logic and Actuation Relays	2	1	2	1, 2, 3, 4	17
3) Safety Injection	See Item 1. above for all Safety Injection initiating functions and requirements.				
4. Steam Line Isolation					
a. Manual Initiation	1/steam line	1/steam line	1/operating steam line	1, 2, 3	22
b. Automatic Actuation Logic and Actuation Relays	2	1	2	1, 2, 3	20
c. Containment Pressure--High-High	4	2	3	1, 2, 3	16
d. Steam Flow in Two Steam Lines--High	2/steam line	1/steam line any 2 steam lines	1/steam line	1, 2, 3	15*
Coincident With Either T_{avg}--Low-Low	4 (1 T_{avg}/loop)	2	3	1, 2, 3	15*
Or Steam Line Pressure-Low	4 (1 pressure/loop)	2	3	1, 2, 3	15*

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TABLE 3.3-3 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
2. Containment Spray (Continued)					
c. Containment Pressure--High-High	4	2	3	1, 2, 3	16
3. Containment Isolation					
a. Phase "A" Isolation					
1) Manual Initiation	2	1	2	1, 2, 3, 4	18
2) Automatic Actuation Logic and Actuation Relays	2	1	2	1, 2, 3, 4	14
3) Safety Injection	See Item 1. above for all Safety Injection initiating functions and requirements				
b. Phase "B" Isolation					
1) Manual Initiation	2 pair	1 pair operated simultaneously	2 pair	1, 2, 3, 4	18
2) Automatic Actuation Logic and Actuation Relays	2	1	2	1, 2, 3, 4	14
3) Containment Pressure--High-High	4	2	3	1, 2, 3	16

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TABLE 3.3-3 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
1. Safety Injection (Reactor Trip, Turbine Trip, Feedwater Isolation, Control Room Isolation, Start Diesel Generators, Component Cooling Water, and Essential Raw Cooling Water) (Continued)					
f. Steam Flow in Two Steam Lines-High	2/steam line	1/steam line any 2 steam lines	1/steam line	1, 2, $3^{\#\#}$	15*
Coincident With Either					
T_{avg}-Low-Low	4 (1 T_{avg}/loop)	2	3	1, 2, $3^{\#\#}$	15*
Or					
Steam Line Pressure-Low	4 (1 pressure/) loop)	2	3	1, 2, $3^{\#\#}$	15*
2. Containment Spray					
a. Manual Initiation	2 pair	1 pair operated simultaneously	2 pair	1, 2, 3, 4	18
b. Automatic Actuation Logic and Actuation Relays	2	1	2	1, 2, 3, 4	14

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

The Engineered Safety Features Actuation System interlocks perform the following functions:

P-4 Reactor tripped - Actuates Turbine trip, closes main feedwater valves on T_{avg} below Setpoint, prevents the opening of the main feedwater valves which were closed by a Safety Injection or High Steam Generator Water Level signal, allows Safety Injection block so that components can be reset or tripped, blocks steam dump via load rejection controller and arms steam dump via plant trip controller.

Reactor not tripped - prevents manual block of Safety Injection.

P-11 On increasing pressurizer pressure, P-11 automatically reinstates Safety Injection actuation on low pressurizer pressure. On decreasing pressure, P-11 allows the manual block of Safety Injection actuation on low pressurizer pressure.

P-12 On increasing reactor coolant loop temperature, P-12 automatically reinstates Safety Injection actuation on high steam flow coincident with either low-low T_{avg} or low steam line pressure, and provides an arming signal to the steam dump system. On decreasing reactor coolant loop temperature, P-12 allows the manual block of Safety Injection actuation on high steam flow coincident with either low-low T_{avg} or low steam line pressure and automatically removes the arming signal from the Steam Dump System.

P-14 On increasing steam generator water levels, P-14 automatically trips all feedwater pumps, initiates a turbine trip, closes the feedwater isolation valves, and inhibits feedwater control valve modulation. On decreasing steam generator water level, P-14 allows the start of all feedwater pumps, permits turbine operation, allows feedwater isolation valve opening, and allows feedwater control valve modulation.

3/4.3.3 MONITORING INSTRUMENTATION

3/4.3.3.1 RADIATION MONITORING FOR PLANT OPERATIONS

The OPERABILITY of the radiation monitoring instrumentation for plant operations ensures that: (1) the associated action will be initiated when the radiation level monitored by each channel or combination thereof reaches its Setpoint, (2) the specified coincidence logic is maintained, and (3) sufficient redundancy is maintained to permit a channel to ~~be out-of-service~~ for testing or maintenance. The radiation monitors for plant operations sense radiation levels in selected plant systems and locations and determines whether or not predetermined limits are being exceeded. If they are, the signals are combined into logic matrices sensitive to combinations indicative of various accidents and abnormal conditions. Once the required logic ~~combination~~ is completed, the system sends actuation signals to initiate alarms or automatic isolation action and actuation of Emergency Exhaust or Ventilation Systems. The radiation monitor Setpoints given in the requirements are assumed to be values established above normal background radiation levels for the particular area.

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FLOW PATHS - OPERATING

LIMITING CONDITION FOR OPERATION

3.1.2.2 At least two of the following three boron injection flow paths shall be OPERABLE:

a. The flow path from the boric acid tanks via a boric acid transfer pump and a charging pump to the Reactor Coolant System; and

b. Two flow paths from the refueling water storage tank via charging pumps to the Reactor Coolant System.

APPLICABILITY: MODES 1, 2, and 3.

ACTION:

With only one of the above required boron injection flow paths to the Reactor Coolant System OPERABLE, restore at least two boron injection flow paths to the Reactor Coolant System to OPERABLE status within 72 hours or be in at least HOT STANDBY and borated to a SHUTDOWN MARGIN equivalent to at least 1% $\Delta k/k$ at 200°F within the next 6 hours; restore at least two flow paths to OPERABLE status within the next 7 days or be in ~~COLD~~ HOT SHUTDOWN within the next 30 hours.

SURVEILLANCE REQUIREMENTS

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

a. At least once per 7 days by verifying that the temperature of the heat traced portion of the flow path from the boric acid tanks is greater than or equal to 145°F when it is a required water source;

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

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

d. At least once per 18 months by verifying that the flow path required by Specification 3.1.2.2a. delivers at least 10 gpm to the Reactor Coolant System.

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CHARGING PUMPS - OPERATING

LIMITING CONDITION FOR OPERATION

3.1.2.4 At least two charging pumps shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTION:

With only one charging pump OPERABLE, restore at least two charging pumps to OPERABLE status within 72 hours or be in at least HOT STANDBY and borated to a SHUTDOWN MARGIN equivalent to at least 1% $\Delta k/k$ at 200°F within the next 6 hours; restore at least two charging pumps to OPERABLE status within the next 7 days or be in HOT SHUTDOWN within the next 6 hours.

SURVEILLANCE REQUIREMENTS

4.1.2.4 At least two charging pumps shall be demonstrated OPERABLE by verifying ~~that~~ a discharge pressure ~~across each pump~~ of greater than or equal to 2400 psig is developed when tested pursuant to Specification 4.0.5.

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TABLE 3.3-6 (Continued)

TABLE NOTATIONS

*With fuel in the fuel storage areas.

**400 cpm is equivalent to 1 x 10-5 mCi/cm3 of Xe-133.

ACTION STATEMENTS

ACTION 27 - With the number of OPERABLE channels one less than the Minimum Channels OPERABLE requirement, within 1 hour isolate the Control Room Ventilation System and initiate operation of the Control Room Ventilation System in the recirculation mode.

ACTION 28 - With the number of OPERABLE channels one less than the Minimum Channels OPERABLE requirement, ACTION a. of Specification 3.9.12 must be satisfied. With both channels inoperable, provid an appropriate portable continuous monitor with the same Alarm Setpoint in the fuel pool area and satisfy ACTION b. of Specification 3.9.12 with one Auxiliary Building Gas Treatment System train in operation.

ACTION 29 - Must satisfy the ACTION requirement for Specification 3.4.6.1.

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4.3.3.8.3 One of the above required infrared or thermal detection instruments in each zone which are accessible during plant operation shall be demonstrated OPERABLE at least once per ~~6 months~~ by performing a TRIP ACTUATING DEVICE OPERATIONAL TEST. Fire dectectors which are not accessible during plant operation shall be demonstrated OPERABLE by the performance of a TRIP ACTUATING DEVICE OPERATIONAL TEST ~~on one~~ of the above required infrared or thermal detection instruments in each zone during each COLD SHUTDOWN exceeding 24 hours unless performed in the previous 6 months. Detectors shall be selected from the previously untested instruments until all infrared or thermal detectors have been tested.

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TABLE 3.3-11 (Continued)

FIRE DETECTION INSTRUMENTATION

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ZONE	INSTRUMENT LOCATION	TOTAL NUMBER OF INSTRUMENTS** HEAT (x/y)	FLAME (x/y)	SMOKE (x/y)
C.	Auxiliary Building ~~(Containment)~~ (Continued)			
132	Ventilation & Purge Air Rm., El. 737			0/5
133	Ventilation & Purge Air Rm., El. 737			0/5
134	Aux. Bldg. A5-A11, Col. U-W, El. 737			0/7
135	Aux. Bldg. A5-A11, Col. U-W, El. 737			0/7
136	Heating & Vent Rm., El. 737			0/4
137	Heating & Vent Rm., El. 737			0/4
140	Hot Instrument Shop, El. 737			0/1
141	Hot Instrument Shop, El. 737			0/1
142	Aux. Bldg. A1-A8, Col. Q-U, El. 737			0/13
143	Aux. Bldg. A1-A8, Col. Q-U, El. 737			0/13
144	Aux. Bldg. A8-A15, Col. Q-U, El. 737			0/10
145	Aux. Bldg. A8-A15, Col. Q-U, El. 737			0/10
146	N_2 Storage, El. 729			4/0
155	Refueling Rm., El. 757			21/0
156	Reactor Bldg. Access Rm., El. 757			0/2
157	Reactor Bldg. Access Rm., El. 757			0/2
160	SG Blwdn. Rm. (Reverse Osmosis), El. 757			0/4
161	SG Blwdn. Rm., El. 757			0/4
162	EGTS Rm., El. 757			0/3
163	EGTS Rm., El. 757			0/3
164	EGTS Fltr. A, El. 757			0/1
165	EGTS Fltr. A, El. 757			0/1
166	EGTS Fltr. B, El. 757			0/1

TABLE 3.3-12

RADIOACTIVE LIQUID EFFLUENT MONITORING INSTRUMENTATION

INSTRUMENT	MINIMUM CHANNELS OPERABLE	ACTION
1. Radioactivity Monitors Providing alarm and Automatic Termination of Release		
a. Waste Disposal System Liquid Effluent Line (RE-90-~~120~~ 122 ~~and 121~~)	1	31
b. Steam Generator Blowdown Effluent Line (RE-90-~~122~~ 120 and 121)	1	32
c. Condensate Demineralizer Regenerant Effluent Line (RE-90-225)	1	31
2. Radioactivity Monitors Providing Alarm But Not Providing Automatic Termination of Release		
a. Essential Raw Cooling Water Effluent Line (RE-90-133 & 90-140 or RE-90-134 & 90-141)	1	33
b. Turbine Building Sump Effluent Line (RE-90-212)	1	33
c. Plant Liquid Discharge Line (RE-90-211)	1	33
3. Flow Rate Measurement Devices		
a. Waste Disposal System Liquid Radwaste Effluent Line	1	34
b. Condensate Demineralizer Regenerant Effluent Line	1	34
c. Steam Generator Blowdown Effluent Line	1	34
d. Diffuser Discharge Effluent Line	1	34
4. Tank Level Indicating Devices		
a. Condensate Storage Tank	1	35
b. Steam Generator Layup Tank*	1	35

*Required when connected to the Secondary Coolant System.

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TABLE 4.3-8

RADIOACTIVE LIQUID EFFLUENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK	SOURCE CHECK	CHANNEL CALIBRATION	ANALOG CHANNEL OPERATIONAL TEST
1. Radioactivity Monitors Providing Alarm and Automatic Termination of Release				
a. Waste Disposal System Liquid Effluent Line (RE-90-~~120 and 121)~~ 122)	D	P	R(3)	Q(1)
b. Steam Generator Blowdown Effluent Line (RE-90-~~124)~~ 120 and 121)	D	M	R(3)	Q(1)
c. Condensate Demineralizer Regenerant Effluent Line (RE-90-225)	D	M	R(3)	Q(1)
2. Radioactivity Monitors Providing Alarm But Not Providing Automatic Termination of Release				
a. Essential Raw Cooling Water Effluent Line (RE-90-133 & 90-140 or RE-90-134 & 90-141)	D	M	R(3)	Q(2)
b. Turbine Building Sump Effluent Line (RE-90-212)	D	M	R(3)	Q(2)
c. Plant Liquid Discharge Line (RE-90-211)	D	M	R(3)	Q(~~1~~) 2
3. Flow Rate Measurement Devices				
a. Waste Disposal System Liquid Effluent Line	D(4)	N.A.	R	Q
b. Steam Generator Blowdown Effluent Line	D(4)	N.A.	R	Q
c. Condensate Demineralizer Regenerant Effluent Line	D(4)	N.A.	R	Q
d. Diffuser Discharge Effluent Line	D(4)	N.A.	R	Q
4. Tank Level Indicating Devices				
a. Condensate Storage Tank	D*	N.A.	R	Q
b. Steam Generator Layup Tank	D*	N.A.	R	N.A.

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TABLE 4.3-9 (Continued)

RADIOACTIVE GASEOUS EFFLUENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK	SOURCE CHECK	CHANNEL CALIBRATION	ANALOG CHANNEL OPERATIONAL TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
4. Shield Building Exhaust System (Continued)					
e. Sampler Flow Rate Measuring Device	D	N.A.	R	Q	***
f. Monitor Flow Rate Measuring Device	D	N.A.	R	Q	***
5. Auxiliary Building Ventilation And Fuel Handling Area Ventilation System (RE-90-101)					
a. Noble Gas Activity Monitor - Providing Alarm and Automatic Termination of Release	D	M	R(3)	Q(1)	*
b. Iodine Sampler	W	N.A.	N.A.	N.A.	*
c. Particulate Sampler	W	N.A.	N.A.	N.A.	*
d. Effluent System Flow Rate Measuring Device	D	N.A.	R	Q	*
e. Sampler Flow Rate Measuring Device	D	N.A.	R	Q	*
f. Monitor Flow Rate Measuring Device	D	N.A.	R	Q	*
6. Service Building Ventilation System (RE-90-132)					
a. Noble Gas Actvity Monitor	D	M	R(3)	Q(2)	*
b. Effluent System Flow Rate Measuring Device	D	N.A.	R	Q	*
c. Monitor Flow Rate Measuring Device	D	N.A.	R	Q	*
7. Containment Purge and Exhaust System (RE-90-130/131) Noble Gas Activity Monitor - Providing Alarm and Automatic Termination of Release	D	P	R(3)	Q(1)	*

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SURVEILLANCE REQUIREMENTS (Continued)

3) Verifying a system flow rate of 4000 cfm ± 10% during system operation when tested in accordance with ANSI N510-1975.

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 pressure drop across the combined HEPA filters and charcoal adsorber banks is less than 8 inches Water Gauge while operating the system at a flow rate of 4000 cfm ± 10%,

2) Verifying that the system starts automatically on a Phase "A" Isolation test signal,

3) Verifying that the filter cooling bypass valves can be opened,

4) Verifying that the air-cleanup subsystem maintains the annulus building at a pressure equal to or more negative than minus 0.5 inches Water Gauge relative to the ~~Shutdown Board Room~~ Mechanical Equipment Room with an inleakage of less than or equal to 100 cfm, and

5) Verifying that the heaters dissipate 20 ± 2.0 kW when tested in accordance with ANSI N510-1975.

e. After each complete or partial replacement of a HEPA filter bank by verifying that the cleanup system satisfies the in-place penetration and bypass leakage testing acceptance criteria of less than 0.05% in accordance with ANSI N510-1975 for a DOP test aerosol while operating the system at a flow rate of 4000 cfm ± 10%; and

f. After each complete or partial replacement of a charcoal adsorber bank by verifying that the cleanup system satisfies the in-place penetration and bypass leakage testing acceptance criteria of less than 0.05% in accordance with ANSI N510-1975 for a halogenated hydrocarbon refrigerant test gas while operating the system at a flow rate of 4000 cfm ± 10%.

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IES

3/4.7.12 FIRE RATED ASSEMBLES

LIMITING CONDITION FOR OPERATION

3.7.12 All fire rated assemblies (walls, floor/ceilings, cable tray enclosures and other fire barriers) separating safety-related fire areas or separating portions of redundant systems important to safe shutdown within a fire area and all sealing devices in fire rated assembly penetrations (fire doors, fire windows, fire dampers, cable, piping, and ventilation duct penetration seals) shall be OPERABLE.

APPLICABILITY: At all times.

ACTION:

a. With one or more of the above required fire rated assemblies and/or sealing devices inoperable, within 1 hour either establish a continuous fire watch on at least one side of the affected assembly, or verify the OPERABILITY of fire detectors on at least one side of the inoperable assembly and establish an hourly fire watch patrol.

b. The provisions of Specifications 3.0.3 and 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.7.12.1 At least once per 18 months the above required fire rated assemblies and penetration sealing devices shall be verified OPERABLE by performing a visual inspection of:

a. The exposed surfaces of each fire rated assembly,

b. Each fire window/fire damper/and associated hardware, and

c. At least 10% of each type of sealed penetration. If apparent changes in appearance or abnormal degradations are found, a visual inspection of an additional 10% of each type of sealed penetration shall be made. This inspection process shall continue until a 10% sample with no apparent changes in appearance or abnormal degradation is found. Samples shall be selected such that each penetration seal will be inspected every 15 years.

b) A kinematic viscosity at 40°C of greater than or equal to 1.9 centistokes, but less than or equal to 4.1 centistokes, if gravity was not determined by comparison with the supplier's certification;

c) A flash point equal to or greater than 125°F; and

d) A clear and bright appearance with proper color when tested in accordance with ASTM-D4176-82.

2) By verifying within 30 days of obtaining the sample that the other properties specified in Table 1 of ASTM-D975-81 are met when tested in accordance with ASTM-D975-81 except that the analysis for sulfur may be performed in accordance with ASTM-D1552-79 or ASTM-D2622-82.

e. At least once every 31 days by obtaining a sample of fuel oil in accordance with ASTM-D2276-78, and verifying that total particulate contamination is less than 10 mg/liter when checked in accordance with ASTM-D2276-78, Method A;

f. At least once per 18 months during shutdown by:

1) Subjecting the diesel to an inspection in accordance with procedures prepared in conjunction with its manufacturer's recommendations for this class of standby service;

2) Verifying the generator capability to reject a load of greater than or equal to ~~640~~ 600 kW while maintaining voltage (steady state) at 6900 ± 690 volts and frequency at 60 ± 1.2 Hz;

3) Verifying the generator capability to reject a load of 4400 kW without tripping. The generator voltage shall not exceed 7866 volts during and following the load rejection;

4) Simulating a loss-of-offsite power by itself, and:

a) Verifying deenergization of the shutdown boards and load shedding from the shutdown boards, and

b) Verifying the diesel starts on the auto-start signal, energizes the shutdown boards with permanently connected loads within 10 seconds, energizes the auto-connected

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these limits during this test. Within 5 minutes after completing this 24-hour test, perform Specification 4.8.1.1.2.~~d~~ f.6)b);*

8) Verifying that the auto-connected loads to each diesel generator do not exceed the 2000-hour rating of ~~4400~~ 4840 kW;

9) Verifying the diesel generator's capability to:

   a) Synchronize with the offsite power source while the generator is loaded with its emergency loads upon a simulated restoration of offsite power,

   b) Transfer its loads to the offsite power source, and

   c) Be restored to its standby status.

10) Verifying that the automatic load sequence timers are OPERABLE and their Setpoints are within the specified bands; and

11) Verifying that the following diesel generator lockout features prevent diesel generator starting only when required:

   a) Engine overspeed, or

   b) 86 GA lockout relay, or

   c) Emergency stop.

g. At least once per 10 years or after any modifications which could affect diesel generator interdependence by starting all diesel generators simultaneously, during shutdown, and verifying that all diesel generators accelerate to 900 ± 18 rpm in less than or equal to 10 seconds; and

*If Specification 4.8.1.1.2.~~d~~ f.6)b) is not satisfactorily completed, it is not necessary to repeat the preceding 24-hour test. Instead, the diesel generator may be operated at 4400 kW for 1 hour or until operating temperature has stabilized.

3/4.8.3 ONSITE POWER DISTRIBUTION

OPERATING

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LIMITING CONDITION FOR OPERATION

3.8.3.1 The Shutdown Board Room chillers shall be OPERABLE and the following electrical busses shall be energized in the specified manner with tie breakers open both between redundant busses within the unit and between units at the same station:

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

   6900-Volt Shutdown Board 1A-A,
   480-Volt Shutdown Board 1A1-A,
   480-Volt Shutdown Board 1A2-A,
   6900-Volt Shutdown Board 2A-A,
   480-Volt Shutdown Board 2A1-A, and
   480-Volt Shutdown Board 2A2-A.

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

   6900-Volt Shutdown Board 1B-B,
   480-Volt Shutdown Board 1B1-B,
   480-Volt Shutdown Board 1B2-B,
   6900-Volt Shutdown Board 2B-B,
   480-Volt Shutdown Board 2B1-B, and
   480-Volt Shutdown Board 2B2-B.

c. 120-Volt A.C. Vital Channels 1-I and 2-I energized from its associated inverter, connected to D.C. Channel I;*

d. 120-Volt A.C. Vital Channels 1-II and 2-II energized from its associated inverter, connected to D.C. Channel II;*

e. 120-Volt A.C. Vital Channels 1-III and 2-III energized from its associated inverter, connected to D.C. Channel III;*

f. 120-Volt A.C. Vital Channels 1-IV and 2-IV energized from its associated inverter, connected to D.C. Channel IV;*

g. 125-Volt D.C. Board I energized from Vital Battery Bank I;

h. 125-Volt D.C. Board II energized from Vital Battery Bank II;

i. 125-Volt D.C. Board III energized from Vital Battery Bank III; and

j. 125-Volt D.C. Board IV energized from Vital Battery Bank IV.

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

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*Two inverters may be disconnected from their D.C. Bus for up to 24 hours as necessary, for the purpose of perfoming an equalizing charge on their associated battery bank provided: ~~(1) the~~ vital busses are energized; and (2) the vital busses associated with the other battery bank are energized from their associated inverters and connected to their associated D.C. bus.

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TABLE 3.8-1 (Continued)

CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

PRIMARY DEVICE NUMBER	BACKUP DEVICE NUMBER	LOCATION OF DEVICES	SYSTEM POWERED
2. 480V Boards (Continued)			
52-213 -6D/A2	FU-213 -A26/32	REAC MOV BD 1A2-A	RHR SYS ISLN BYPASS VLV
52-213 -7D/A2	FU-213 -A27/32	REAC MOV BD 1A2-A	LWR CNTMT 1A CLR DISCH ISLN VLV
52-213 -8D/A2	FU-213 -A28/32	REAC MOV BD 1A2-A	LWR CNTMT 1C CLRS
52-213 -9D/A2	FU-213 -A29/32	REAC MOV BD 1A2-A	UPR CNTMT VT CLR 1A DISCH TS
52-213 -6D/B2	FU-213 -B212/32	REAC MOV BD 1B2-B	RCP THRM BAR RTN CNTMT ISLN
52-213 -7D/B2	FU-213 -B27/32	REAC MOV BD 1B2-B	LWR CNTMT 1B CLRS DISCH ISLN
52-213 -8D/82	FU-213 -B28/32	REAC MOV BD 1B2-B	LWR CNTMT ID CLRS DISCH ISLN
52-213 -9D/B2	FU-213 -B29/32	REAC MOV BD 1B2-B	UPR CNTMT VT CLR 1B DISCH ISLN
52-213 -10D/B2	FU-213 -B210/31	REAC MOV BD 1B2-B	UPR CNTMT VT CLR 1D DISCH ISLN
52-213 -13D/B2	FU-213 -B213/32	REAC MOV BD 1B2-B	RCP OIL CLR RTN CNTMT ISLN
52-232 -2A/1A	FU-232 -A2/2	REAC VENT BD 1A-A	CNTMT FL & EQ DR SMP PMP 1A
52-232 -3A/1A	FU-232 -A3/2	REACT VENT BD 1A-A	INCORE FLUX DET DRIVE UNIT 1D
52-232 -3B/1A	FU-232 -A3/12	REAC VENT BD 1A-A	INCORE FLUX DET DRIVE UNIT 1E
52-232 -3C/1A	FU-232 -A3/22	REAC VENT BD 1A-A	INCORE FLUX DET DRIVE UNIT 1F

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TABLE 3.8-1 (Continued)

CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

PRIMARY DEVICE NUMBER	BACKUP DEVICE NUMBER	LOCATION OF DEVICES	SYSTEM POWERED
2. 480V Boards (Continued)			
52-232 -10F/1B	FU-232 -B10/52	REAC VENT BD 1B-B	REAC BLDG JIB CRN
52-232 -11D/1B	FU-232 -B11/32	REAC VENT BD 1B-B	REAC COOL DR TK PMP 1B
52-232 -11F/1B	FU-232 -B11/52	REAC VENT BD 1B-B	REAC LWR COMPT U HTR 1B
52-232 -12F/1B	FU-232 -B12/52	REAC VENT BD 1B-B	CNTMT INST RM U HTR 1B
52-232 -13B/1B	FU-232 -B13/11	REAC VENT BD 1B-B	IC END WALL DR 1B
52-232 -13D/1B	FU-232 -B13/32	REAC VENT BD 1B-B	IC AHU(S)
52-232 -13F/1B	FU-232 -B13/52	REAC VENT BD 1B-B	IC BRIDGE CRN
52-232 -14B/1B	FU-232 -B14/12	REAC VENT BD 1B-B	RCC CHANGE HOIST
52-232 -14D/1B	FU-232 -B14/31	REAC VENT BD 1B-B	IC AHU(S)
52-232 -14F/1B	FU-232 -B14/52	REAC VENT BD 1B-B	EQPT HATCH HOIST
52-232 -15A/1B	FU-232 -B15/2	REAC VENT BD 1B-B	REAC UPR COMPT HTR 1B
52-232 -16A/1B	FU-232 -B16/2	REAC VENT BD 1B-B	REAC UPR COMPT HTR 1D
3. 480V AC CAB			
CB-68 -341F/D1	FU-211 -A21/4	DIST CAB CONT GP 1D	PRESSURIZER HTRS GP 1D ELEMENTS 47, 49, 51

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TABLE 3.8-1 (Continued)

CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

PRIMARY DEVICE NUMBER	BACKUP DEVICE NUMBER	LOCATION OF DEVICES	SYSTEM POWERED
3. 480V AC CAB (Continued)			
CB-68 -341A/A4-A	FU-211 -A20/7	DIST CAB CONT GP 1A-A	PRESSURIZER HTRS GP 1A-A ELEMENTS 42, 40, 44
CB-68 -341A/A5-A	FU-211 -A20/8	DIST CAB CONT GP 1A-A	PRESSURIZER HTRS GP 1A-A ELEMENTS 5, 3, 7
CB-68 -341A/A6-A	FU-211 -A20/9	DIST CAB CONT GP 1A-A	PRESSURIZER HTRS GP 1A-A ELEMENTS 11, 9, 13
CB-68 -341A/A7-A	FU-211 -A20/10	DIST CAB CONT GP 1A-A	PRESSURIZER HTRS GP 1A-A ELEMENTS 17, 15, 19
CB-68 -341D/B1-B	FU-211 -B20/4	DIST CAB CONT GP 1B-B	PRESSURIZER HTRS GP 1B-B ELEMENTS 23, 25, 27
CB-68 -341D/B2-B	FU-211 -B20/5	DIST CAB CONT GP 1B-B	PRESSURIZER HTRS GP 1B-B ELEMENTS 29, 31, 33
CB-68 -341D/B3-B	FU-211 -B20/6	DIST CAB CONT GP 1B-B	PRESSURIZER HTRS GP 1B-B ELEMENTS 35, 37, 39
CB-68 -341D/B4-B	FU-211 -B20/7	DIST CAB CONT GP 1B-B	PRESSURIZER HTRS GP 1B-B ELEMENTS 43, 41, 45
CB-68 -341D/B5-B	FU-211 -B20/8	DIST CAB CONT GP 1B-B	PRESSURIZER HTRS GP 1B-B ELEMENTS 4, 2, 6

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TABLE 3.8-2

MOTOR-OPERATED VALVES THERMAL OVERLOAD

BYPASS DEVICES

VALVE NO.	FUNCTION	BYPASS DEVICE
1-FCV-62-63	Isolation for Seal Water Filter	Yes
1-FCV-62-138	Safe Shutdown Redundancy (CVCS)	Yes
1-FCV-62-98	ECCS Operation	Yes
1-FCV-62-99	ECCS Operation	Yes
1-FCV-62-90	ECCS Operation	Yes
1-FCV-62-91	ECCS Operation	Yes
1-FCV-62-61	Cont. Isolation	Yes
1-LCV-62-132	ECCS Operation	Yes
1-LCV-62-133	ECCS Operation	Yes
1-LCV-62-135	ECCS Operation	Yes
1-LCV-62-136	ECCS Operation	Yes
1-FCV-74-1	Open for Normal Plant Cooldown	Yes
1-FCV-74-2	Open for Normal Plant Cooldown	Yes
1-FCV-74-3	ECCS Operation	Yes
1-FCV-74-21	ECCS Operation	Yes
1-FCV-74-12	RHR Pump, Mini-flow Protects Pump	Yes
1-FCV-74-24	RHR Pump, Mini-flow Protects Pumps	Yes
1-FCV-74-33	ECCS Operation	Yes
1-FCV-74-35	ECCS Operation	Yes
1-FCV-63-7	ECCS Operation	Yes
1-FCV-63-6	ECCS Operation	Yes
1-FCV-63-156	ECCS Flow Path	Yes
1-FCV-63-157	ECCS Flow Path	Yes
1-FCV-63-39	BIT Injection	Yes
1-FCV-63-40	BIT Injection	Yes
1-FCV-63-25	BIT Injection	Yes
1-FCV-63-26	BIT Injection	Yes
1-FCV-63-118	RCS Pressure Boundary	Yes
1-FCV-63-98	RCS Pressure Boundary	Yes
1-FCV-63-80	RCS Pressure Boundary	Yes
1-FCV-63-67	RCS Pressure Boundary	Yes
1-FCV-63-1	ECCS Operation	Yes
1-FCV-63-72	ECCS Flow Path from Cont. Sump	Yes
1-FCV-63-73	ECCS Flow Path from Cont. Sump	Yes
1-FCV-63-8	ECCS Flow Path	Yes
1-FCV-63-11	ECCS Flow Path	Yes
1-FCV-63-93	ECCS Cooldown Flow Path	Yes
1-FCV-63-94	ECCS Cooldown Flow Path	Yes
1-FCV-63-172	ECCS Flow Path	Yes
1-FCV-63-5	ECCS Flow Path	Yes
1-FCV-63-47	Train Isolation	Yes
1-FCV-63-48	Train Isolation	Yes
1-FCV-63-4	SI Pump Mini-flow	Yes
1-FCV-63-175	SI Pump Mini-flow	Yes

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TABLE 3.12-1 (Continued)

TABLE NOTATIONS (Continued)

(5) Gamma isotopic analysis means the identification and quantification of gamma-emitting radionuclides that may be attributable to the effluents from the facility.

(6) The "upstream sample" shall be taken at a distance beyond significant influence of the discharge. The "downstream" sample shall be taken in an area beyond but near the mixing zone.

(7) A composite sample is one in which the quantity (aliquot) of liquid sampled is proportional to the quantity of flowing liquid and in which the method of sampling employed results in a specimen that is representative of the liquid flow. In this program composite sample aliquots shall be collected at time intervals that are very short (e.g., hourly) relative to the compositing period (e.g., monthly) in order to assure obtaining a representative sample.

(8) Groundwater samples shall be taken when this source is tapped for drinking or irrigation purposes in areas where the hydraulic gradient or recharge properties are suitable for contamination. Groundwater flow in the area of WBN has been shown to be toward Chickamauga Reservoir. There are no sources tapped for drinking or irrigation purposes between the plant and the reservoir. Therefore, sampling of the medium is not required.

(9) The dose shall be calculated for the maximum organ and age group, using the methodology and parameters in the ODCM.

(10) If harvest occurs more than once a year, sampling shall be performed during each discrete harvest. If harvest occurs continuously, sampling shall be monthly. Attention shall be paid to including samples of tuberous and root food products.

(11) The surface water control shall be considered a control for the drinking water samples.

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STEAM GENERATORS (Continued)

Whenever the results of any steam generator tubing inservice inspection fall into Category C-3, these results will be reported to the Commission within 30 days pursuant to Specification 6.9.2 and prior to resumption of plant operation. Such cases will be considered by the Commission on a case-by-case basis and may result in a requirement for analysis, laboratory examinations, tests, additional eddy-current inspection, and revision of the Technical Specifications, if necessary.

3/4.4.6 REACTOR COOLANT SYSTEM LEAKAGE

3/4.4.6.1 LEAKAGE DETECTION SYSTEMS

The RCS Leakage Detection Systems required by this specification are provided to monitor and detect leakage from the reactor coolant pressure boundary. These Detection Systems are consistent with the recommendations of Regulatory Guide 1.45, "Reactor Coolant Pressure Boundary Leakage Detection Systems," May 1973. The radioactivity monitoring requirements may be satisfied by either RE-90-106 or RE-90-112 provided the system is sampling the lower compartment.

3/4.4.6.2 OPERATIONAL LEAKAGE

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

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

The total steam generator tube leakage limit of 1 gpm for all steam generators not isolated from the RCS ensures that the dosage contribution from the tube leakage will be limited to a small fraction of 10 CFR Part 100 dose guideline values in the event of either a steam generator tube rupture or steam line break. The 1 gpm limit is consistent with the assumptions used in the analysis of these accidents. The 500 gpd leakage limit per steam generator ensures that steam generator tube integrity is maintained in the event of a main steam line rupture or under LOCA conditions.

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

The CONTROLLED LEAKAGE limitation restricts opeation when the total flow supplied to the reactor coolant pump seals exceeds 40 gpm at a nominal RCS pressure of 2235 psig. This limitation ensures that in the event of a LOCA, the Safety Injection flow will not be less than assumed in the safety analyses.

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SPECIFIC ACTIVITY (Continued)

Based upon the above considerations for excluding certain radionuclides from the sample analysis, the allowable time of 2 hours between sample taking and completing the initial analysis is based upon a typical time necessary to perform the sampling, transport the sample, and perform the analysis of about 90 minutes. After 90 minutes the gross count should be made in a reproducible geometry of sample and counter having reproducible beta or gamma self-shielding properities. The counter should be reset to a reproducible efficiency versus energy. It is not necessary to identify specific nuclides. The radiochemical determination of nuclides should be based on multiple counting of the sample with typical counting basis following sampling of less than 1 hour, about 2 hours, about 1 day, about 1 week and about 1 month.

Reducing T_{avg} to less than 500°F with a reduction of RCS pressure prevents the release of activity should a steam generator tube rupture since the saturation pressure of the reactor coolant is below the lift pressure of the atmospheric steam relief valves. The Surveillance Requirements provide adequate assurance that excessive specific activity levels in the reactor coolant will be detected in sufficient time to take corrective action. Information obtained on iodine spiking will be used to assess the parameters associated with spiking phenomena. A reduction in frequency of isotopic analyses following power changes may be permissible if justified by the data obtained.

3/4.4.9 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:

a. 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:

   1. 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

   2. 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.

PRESSURE/TEMPERATURE LIMITS (Continued)

Where: K_{IR} is the reference stress intensity factor as a function of the metal temperature T and the metal nil-ductility reference temperature RT_{NDT}. Thus, the governing equation for the heatup-cooldown analysis is defined in Appendix G of the ASME Code as follows:

$$C\ K_{IM} + K_{It} \leq K_{IR} \qquad (2)$$

Where: K_{IM} = the stress intensity factor caused by membrane (pressure) stress,

K_{It} = the stress intensity factor caused by the thermal gradients,

K_{IR} = the value provided by the Code as a function of temperature relative to the RT_{NDT} of the material,

C = 2.0 for level A and B service limits, and

C = 1.5 for inservice hydrostatic and leak test operations.

At any time during the heatup or cooldown transient, K_{IR} is determined by the metal temperature at the tip of the postulated flaw, the appropriate value for RT_{NDT}, and the reference fracture toughness curve. The thermal stresses resulting from temperature gradients through the vessel wall are calculated and then the corresponding thermal stress intensity factor, K_{It}, for the reference flaw is computed. From Equation (2) the pressure stress intensity factors are obtained and, from these, the allowable pressures are calculated.

COOLDOWN

For the calculation of the allowable pressure versus coolant temperature during cooldown, the Code reference flaw is assumed to exist at the inside of the vessel wall. During cooldown, the controlling location of the flaw is always at the inside of the wall because the thermal gradients produce tensile stresses at the inside, which increase with increasing cooldown rates. Allowable pressure-temperature relations are generated for both steady-state and finite cooldown rate situations. From these relations, composite limit curves are constructed for each cooldown rate of interest.

The use of the composite curve in the cooldown analysis is necessary because control of the cooldown procedure is based on measurement of reactor coolant temperature, whereas the limiting pressure is actually dependent on the material temperature at the tip of the assumed flaw. During cooldown, the 1/4T vessel location is at a higher temperature than the fluid adjacent to the vessel ID. This condition, of course, is not true for the steady-state situation. It follows that at any given reactor coolant temperature, the ΔT developed during cooldown results in a higher value of K_{IR} at the 1/4T location for finite cooldown rates than for steady-state operation. Furthermore, if

3/4.6.4 COMBUSTIBLE GAS CONTROL

The OPERABILITY of the equipment and systems required for the detection and control of hydrogen gas ensures that this equipment will be available to maintain the hydrogen concentration within containment below its flammable limit during post-LOCA conditions. Either recombiner unit is capable of controlling the expected hydrogen generation associated with: (1) zirconium-water reactions, (2) radiolytic decomposition of water, and (3) corrosion of metals within containment. These Hydrogen Control Systems are consistent with the recommendations of Regulatory Guide 1.7, "Control of Combustible Gas Concentrations in Containment Following a LOCA," March 1971.

The Hydrogen Mixing Systems are provided to ensure adequate mixing of the containment atmosphere following a LOCA. This mixing action will prevent localized accumulations of hydrogen from exceeding the flammable limit.

The OPERABILITY of at least 33 of 34 ignitors per train (66 of 68 for both trains) in the Hydrogen Mitigation System will maintain an effective coverage throughout the containment provided the two inoperable ignitors are not on corresponding redundant circuits which provide coverage for the same region. This system of ignitors will initiate combustion of any significant amount of hydrogen released after a degraded core accident. This system is to ensure burning in a controlled manner as the hydrogen is released instead of allowing it to be ignited at high concentrations by a random ignition source.

3/4.6.5 ICE CONDENSER

The requirements associated with each of the components of the ice condenser ensure that the overall system will be available to provide sufficient pressure suppression capability to limit the containment peak pressure transient to less than 15 psig during LOCA conditions.

3/4.6.5.1 ICE BED

The OPERABILITY of the ice bed ensures that the required ice inventory will: (1) be distributed evenly through the containment bays, (2) contain sufficient boron to preclude dilution of the containment sump following the LOCA, and (3) contain sufficient heat removal capability to condense the Reactor Coolant System volume released during a LOCA. These conditions are consistent with the assumptions used in the safety analyses.

The minimum weight figure of 1399 pounds of ice per basket contains a 10% conservative allowance for ice loss through sublimation which is a factor of 10 higher than assumed for the ice condenser design and 1% for weighing accuracies. In the event that observed sublimation rates are equal to or lower than design predictions after 3 years of operation, the minimum ice basket weight may be adjusted downward. In addition, the number of ice baskets required to be weighed each 9 months may be reduced after 3 years of operation if such a reduction is supported by observed sublimation data.

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FIRE RATED ASSEMBLIES (Continued)

Fire barrier penetrations, including cable penetration barriers, fire doors and dampers are considered functional when the visually observed condition is the same as the as-designed condition. For those fire barrier penetrations that are not in the as-designed condition, an evaluation shall be performed to show that the modification has not degraded the fire rating of the fire barrier penetration.

During periods of time when a barrier is not functional, either: (1) a continous fire watch is required to be maintained in the vicinity of the affected barrier, or (2) the fire detectors on at least one side of the affected barrier must be verified OPERABLE and an hourly fire watch patrol established until the barrier is restored to functional status.

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LIQUID HOLDUP TANKS (Continued)

Restricting the quantity of radioactive material contained in the specified tanks provides assurance that in the event of an uncontrolled release of the tanks' contents, the resulting concentrations would be less than the limits of 10 CFR Part 20, Appendix B, Table II, Column 2, at the nearest potable water supply and the nearest surface water supply in an UNRESTRICTED AREA.

3/4.11.2 GASEOUS EFFLUENTS

3/4.11.2.1 DOSE RATE

This specification is provided to ensure that the dose at any time at and beyond the SITE BOUNDARY from gaseous effluents from all units on the site will be within the annual dose limits of 10 CFR Part 20 for UNRESTRICTED AREAS. The annual dose limits are the doses associated with the concentrations of 10 CFR Part 20, Appendix B, Table II, Column 1. These limits provide reasonable assurance that radioactive material discharged in gaseous effluents will not result in the exposure of a MEMBER OF THE PUBLIC in an UNRESTRICTED AREA, either within or outside the SITE BOUNDARY, to annual average concentrations exceeding the limits specified in Appendix B, Table II of 10 CFR Part 20 (10 CFR 20.106(b)). For MEMBERS OF THE PUBLIC who may at times be within the SITE BOUNDARY, the occupancy of that MEMBER OF THE PUBLIC will usually be sufficiently low to compensate for any increase in the atmospheric diffusion factor above that for the SITE BOUNDARY. Examples of calculations for such MEMBERS OF THE PUBLIC, with the appropriate occupancy factors, shall be given in the ODCM. The specified release rate limits restrict, at all times, the corresponding gamma and beta dose rates above background to a MEMBER OF THE PUBLIC at or beyond the SITE BOUNDARY to less than or equal to 500 mrems/year to the total body or to less than or equal to 3000 mrems/year to the skin. These release rate limits also restrict, at all times, the corresponding thyroid dose rate above background to an infant ~~a child~~ via ~~the~~ milk ingestion, ground contamination, and inhalation pathways to less than or equal to 1500 mrems/year.

This specification applies to the release of radioactive materials in gaseous effluents from all reactors at the site.

The required detection capabilities for radioactive materials in gaseous waste samples are tabulated in terms of the lower limits of detection (LLDs). Detailed discussion of the LLD, and other detection limits can be found in HASL Procedures Manual, HASL-300 (revised annually), Currie, L. A., "Limits for Qualitative Detection and Quantitative Determination - Application to Radiochemistry," Anal. Chem. 40, 586-93 (1968), and Hartwell, J. K., "Detection Limits for Radioanalytical Counting Techniques," Atlantic Richfield Hanford Company Report ARH-SA-215 (June 1975).

3/4.11.2.2 DOSE-NOBLE GASES

This specification is provided to implement the requirements of Sections II.B, III.A and IV.A of Appendix I, 10 CFR Part 50. The Limiting

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DOSE - IODINE-131 AND 133, TRITIUM, AND RADIOACTIVE MATERIAL IN PARTICULATE FORM (Continued)

"Calculation of Annual Doses to Man from Routine Releases of Reactor Effluents for the Purpose of Evaluating Compliance with 10 CFR Part 50, Appendix I," Revision 1, October 1977, NUREG/CR-1004, "A Statistical Analysis of Selected Parameters for Predicting Food Chain Transport and Internal Dose of Radionuclides," October 1979, and Regulatory Guide 1.111, "Methods for Estimating Atmospheric Transport and Dispersion of Gaseous Effluents in Routine Releases from Light-Water-Cooled Reactors," Revision 1, July 1977. These equations also provide for determining the actual doses based upon the historical average atmospheric conditions. The release rate specifications for Iodine-131 and 133, tritium, and radionuclides in particulate form with half-lives greater than 8 days are dependent upon the existing radionuclide pathways to man, in the areas at and beyond the SITE BOUNDARY. The pathways that were examined in the development of these calculations were: (1) individual inhalation of airborne radionuclides, (2) deposition of radionuclides onto green leafy vegetation with subsequent consumption by man, (3) deposition onto grassy areas where milk animals and meat producing animals graze with consumption of the milk and meat by man, and (4) deposition on the ground with subsequent exposure of man.

This specification applies to the release of gaseous effluents from each reactor at the site. When shared Radwaste Treatment Systems are used by more than one unit on a site, the wastes from all units are mixed for shared treatment; by such mixing, the effluent releases cannot accurately be ascribed to a specific unit. An estimate should be made of the contributions from each unit based on input conditions, e.g., flow rates and radioactivity concentrations, or, if not practicable, the treated effluent releases be allocated equally to each of the radioactive waste producing units sharing the Radwaste Treatment System. For determining conformance to LCOs, these allocations from shared Radwaste Treatment Systems are to be added to the releases specifically attributed to each unit to obtain the total releases per unit.

3/4.11.2.4 GASEOUS RADWASTE TREATMENT SYSTEM

The OPERABILITY of the Gaseous Radwaste Treatment System and the VENTILATION EXHAUST TREATMENT SYSTEM ensures that the systems will be available for use whenever gaseous effluents require treatment prior to release to the environment. The requirement that the appropriate portions of these systems be used, when specified, provides reasonable assurance that the releases of radioactive materials in gaseous effluents will be kept "as low as is reasonably achievable". This specification implements the requirements of 10 CFR Part 50.36a, General Design Criterion 60 of Appendix A to 10 CFR Part 50, and the design objectives given in Section II.D of Appendix I to 10 CFR Part 50. The specified limits governing the use of appropriate portions of the systems were specified as a suitable fraction of the dose design objectives set forth in Sections II.B and II.C of Appendix I, 10 CFR Part 50, for gaseous effluents. This specification applies to the release of radioactive materials in gaseous effluents from each unit at the site. When shared Radwaste Treatment Systems are used by more than one unit on a site, the wastes from all units are mixed for shared treatment; by such mixing, the effluent releases cannot accurately be ascribed to a specific unit. An estimate should be made of the

RECORDS

6.5.2.7 Records of NSS activities shall be approved and distributed as indicated below:

a. Reports of reviews encompassed by Specification 6.5.2.5 above, shall be approved by the Chief, NSS, and forwarded to the Manager, Office of Nuclear Power, within 14 days following completion of the review; and

b. Audit reports encompassed by Specification 6.5.2.6 above, shall be forwarded to the Manager, Office of Nuclear Power, and to the management positions responsible for the areas audited within 30 days after completion of the audit.

6.5.3 RADIOLOGICAL ASSESSMENT REVIEW COMMITTEE (RARC)

FUNCTION

6.5.3.1 The RARC shall function to advise the Manager, Radiological Services, and the Plant Manager on all matters related to radiological assessments involving dose calculations and projections and environmental monitoring.

COMPOSITION

6.5.3.2 The RARC shall be composed of the:

Chairman:	Assessment Unit Supervisor
Member:	Health Physicist, Gaseous, Health Physics Service
Member:	Health Physicist, Liquid, Health Physics Service
Member:	Meteorologist Engineer, Air Quality Branch
Member:	Chemical Unit Supervisor, Engineering Section, WBNP

ALTERNATES

6.5.3.3 All alternate members shall be appointed in writing by the RARC Chairman to serve on a temporary basis; however, no more than two alternates shall participate as voting members in RARC activities at any one time.

MEETING FREQUENCY

6.5.3.4 The RARC shall meet at least once per 6 months and as convened by the RARC Chairman or his designated alternate.

QUORUM

6.5.3.5 The quorum of the RARC necessary for the performance of the RARC responsibility and authority provisions of these Technical Specifications shall consist of the Chairman or his designated alternate and three members including alternates.

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6.7 SAFETY LIMIT VIOLATION

6.7.1 The following actions shall be taken in the event a Safety Limit is violated:

a. The NRC Operations Center shall be notified by telephone as soon as possible and in all cases within ~~1~~ hour. The Site Director, and the Chief, NSS, shall be notified with 24 hours; within

b. A Safety Limit Violation Report shall be prepared. The report shall be reviewed by the PORC. This report shall describe: (1) applicable circumstances preceding the violation, (2) effects of the violation upon facility components, systems or structures, and (3) corrective action taken to prevent recurrence;

c. The Safety Limit Violation Report shall be submitted to the Commission, the Chief, NSS, and the Site Director within 14 days of the violation; and

d. Operation of the unit shall not be resumed until authorized by the Commission.

6.8 PROCEDURES AND PROGRAMS

6.8.1 Written procedures shall be established, implemented, and maintained covering the activities referenced below:

a. The applicable procedures recommended in Appendix A of Regulatory Guide 1.33, Revision 2, February 1978;

b. The emergency operating procedures required to implement the requirements of NUREG-0737 and Supplement 1 to NUREG-0737 as stated in Section 7.1 of Generic Letter No. 82-33;

c. Plant Physical Security Plan implementation;

d. Site Radiological Emergency Plan implementation;

e. PROCESS CONTROL PROGRAM implementation; and

f. Quality Assurance Program for effluent monitoring.

6.8.2 Each procedure of Specification 6.8.1 above, and changes thereto, shall be reviewed by the PORC and approved by the Plant Manager prior to implementation and reviewed periodically as set forth in administrative procedures.

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HIGH RADIATION AREA (Continued)

a. A radiation monitoring device which continuously indicates the radiation dose rate in the area, or

b. A radiation monitoring device which continuously integrates the radiation dose rate in the area and alarms when a preset integrated dose is received. Entry into such areas with this monitoring device may be made after the dose rate levels in the area have been established and personnel have been made knowledgeable of them; or

c. An individual qualified in radiation protection procedures with a radiation dose rate monitoring device, who is responsible for providing positive control over the activities within the area and shall perform periodic radiation surveillance at the frequency specified by the Health Physics Supervisor in the RWP.

6.12.2 In addition to the requirements of Specification 6.12.1, areas accessible to personnel with radiation levels greater than 1000 mR/h at 45 cm (18 in.) from the radiation source or from any surface which the radiation penetrates shall be provided with locked doors to prevent unauthorized entry, and the keys shall be maintained under the administrative control of the Shift Foreman on duty and/or health physics supervision. Doors shall remain locked except during periods of access by personnel under an approved RWP which shall Specify the dose rate levels in the immediate work areas and the maximum allowable stay time for individuals in that area. In lieu of the stay time specification of the RWP, direct or remote (such as closed circuit TV cameras) continuous surveillance may be made by personnel qualified in radiation protection procedures to provide positive exposure control over the activiites being performed within the area.

For individual high radiation areas accessible to personnel with radiation levels of greater than 1000 mR/h that are located within large areas, such as PWR containment, where no enclosure exists for purposes of locking, and where no enclosure can be reasonably constructed around the individual area, that individual area shall be barricaded, conspicuously posted, and a flashing light shall be activiated as a warning device.

6.13 PROCESS CONTROL PROGRAM (PCP)

6.13.1 The PCP shall be approved by the Commission prior to implementation.

6.13.2 Licensee-initiated changes to the PCP:

a. Shall be submitted to the Commission in the Semiannual Radioactive Effluent Release Report for the period in which the change(s) was made. This submittal shall contain:

1) Sufficiently detailed information to totally support the rationale for the change without benefit of additional or supplemental information;

2) A determination that the change did not reduce the overall conformance of the solidified waste product to existing criteria for solid wastes; and

3) Documentation of the fact that the change has been reviewed and found acceptable by the PORC.

b. Shall become effective upon review and acceptance by the PORC.

6.14 OFFSITE DOSE CALCULATION MANUAL (ODCM)

6.14.1 The ODCM shall be approved by the Commission prior to implementation.

6.14.2 Licensee-initiated changes to the ODCM:

a. Shall be submitted to the Commission in the Semiannual Radioactive Effluent Release Report for the period in which the change(s) was made effective. This submittal shall contain:

1) Sufficiently detailed information to totally support the rationale for the change without benefit of additional or supplemental information. Information submitted should consist of a package of those pages of the ODCM to be changed with each page numbered, dated and containing the revision number, together with appropriate analyses or evaluations justifying the change(s);

2) A determination that the change will not reduce the accuracy or reliability of dose calculations or Setpoint determinations; and

3) Documentation of the fact that the change has been reviewed and found acceptable by the RARC.

b. Shall become effective upon review and acceptance by the RARC.

6.15 MAJOR CHANGES TO LIQUID, GASEOUS, AND SOLID RADWASTE TREATMENT SYSTEMS*

6.15.1 Licensee-initiated major changes to the Radwaste Treatment Systems (liquid, gaseous, and solid):

a. Shall be reported to the Commission in the Semiannual Radioactive Effluent Release Report for the period in which the evaluation was reviewd by the PORC. The discussion of each change shall contain:

1) A summary of the evaluation that led to the determination that the change could be made in accordance with 10 CFR 50.59;

*Licensees may choose to submit the information called for in this specification as part of the annual FSAR update.

FIGURE 2.1-1 REACTOR CORE SAFETY LIMIT [illegible]

Figure 2.1-1 has been revised to reflect the reactor core safety limits for Watts Bar.

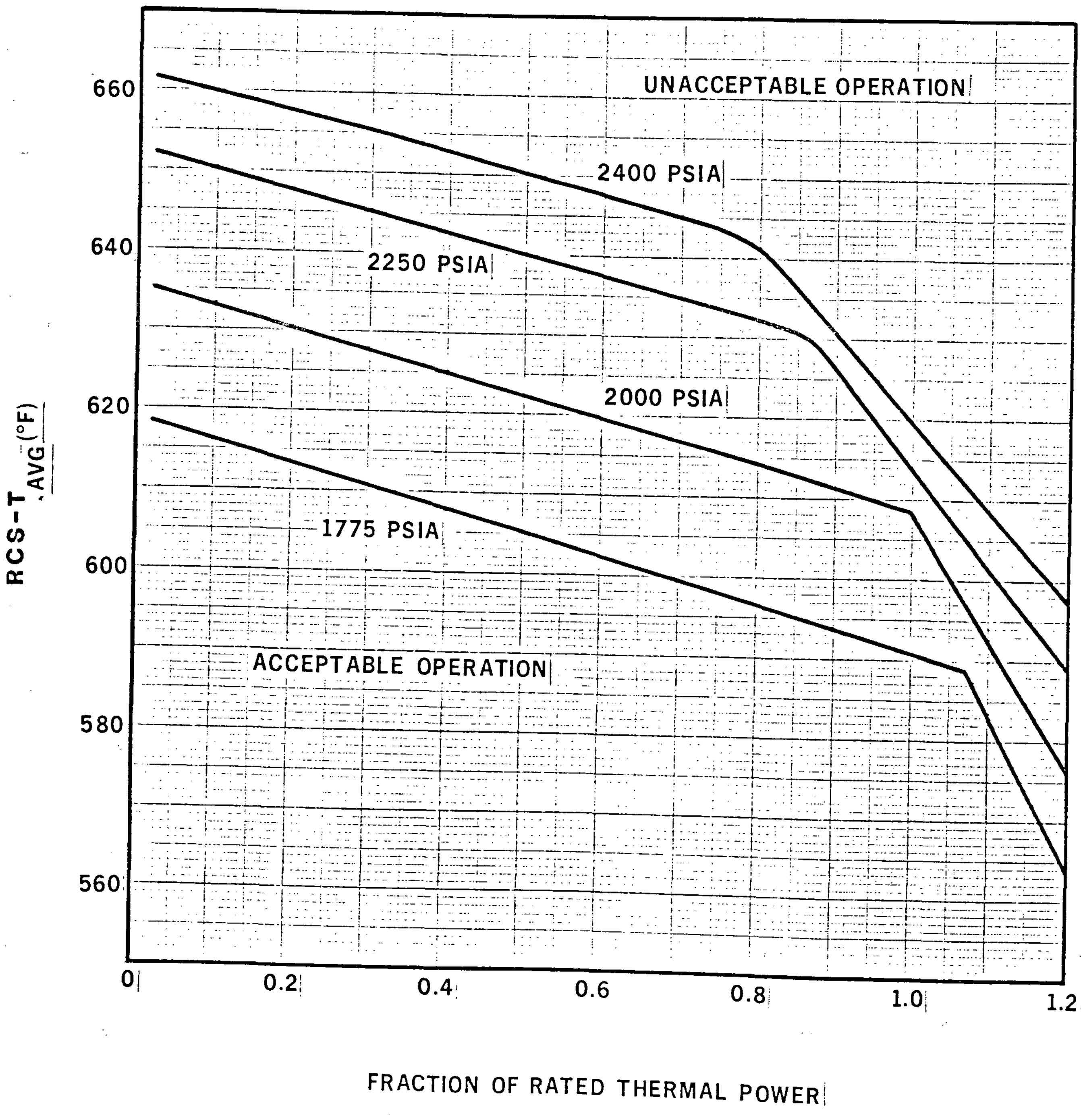

FIGURE 2.1-1

REACTOR CORE SAFETY LIMIT - FOUR LOOPS IN OPERATION

Table 2.2-1 - Reactor Protection Setpoints

The reactor protection allowable values have been revised to include the allowances provided in the setpoint study. The setpoint study has been previously submitted to NRC.

TABLE 2.2-1

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
1. Manual Reactor Trip	N.A.	N.A.
2. Power Range, Neutron Flux		
a. Low Setpoint	≤ 25% of RATED THERMAL POWER	≤ ~~26%~~ 27.4 of RATED THERMAL POWER
b. High Setpoint	≤ 109% of RATED THERMAL POWER	≤ ~~110%~~ 111.4 of RATED THERMAL POWER
3. Power Range, Neutron Flux, High Positive Rate	≤ 5% of RATED THERMAL POWER with a time constant ≥ 2 seconds	≤ ~~5.5%~~ 6.3 of RATED THERMAL POWER with a time constant ≥ 2 seconds
4. Power Range, Neutron Flux, High Negative Rate	≤ 5% of RATED THERMAL POWER with a time constant ≥ 2 seconds	≤ ~~5.5%~~ 6.3 of RATED THERMAL POWER with a time constant ≥ 2 seconds
5. Intermediate Range, Neutron Flux	≤ 25% of RATED THERMAL POWER	≤ ~~30%~~ 31.2 of RATED THERMAL POWER
6. Source Range, Neutron Flux	≤ 10^5 cps	≤ ~~1.5~~ 1.4 x 10^5 cps
7. Overtemperature ΔT	See Note 1	See Note 2
8. Overpower ΔT	See Note 3	See Note 4
9. Pressurizer Pressure--Low	≥ 1970 psig	≥ ~~1950~~ 1954 psig
10. Pressurizer Pressure--High	≤ 2385 psig	≤ ~~2395~~ 2401 psig
11. Pressurizer Water Level--High	≤ 92% of instrument span	≤ ~~93%~~ 94 of instrument span
12. Reactor Coolant Flow-Low-Single Loop (Above P-8)	≥ 90% of design flow per loop*	≥ ~~89%~~ 88.7 of design flow per loop*
13. Reactor Coolant Flow-Low-Two Loops (Above P-7 and Below P-8)	≥ 90% of design flow per loop*	≥ ~~89%~~ 88.7 of design flow per loop*

*Design flow is 97,500 gpm per loop.

TABLE 2.2-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
14. Steam Generator Water Level--Low-Low	≥ 17% of narrow range span between 0 and 35% load, increasing linearly to ≥ 54.9% of narrow range span at 100% of nominal load	≥ ~~15.6~~ 15.0% of narrow range span between 0 and 35% load increasing linearly to ≥ 53.5% of narrow range span at 100% of nominal load
15. Steam Generator Water Level-Low Coincident With Steam/Feedwater Flow Mismatch	≤ ~~40%~~ 38 of full steam flow at RATED THERMAL POWER coincident with steam generator water level ≥ 17% narrow range span between 0 and 35% load, increasing linearly to ≥ 54.9% of narrow range span at 100% of nominal load	≤ ~~42.5%~~ 41.5 of full steam flow at RATED THERMAL POWER coincident with steam generator water level ≥ ~~15.6%~~ 15.0 of narrow range span between 0 and 35% load, increasing linearly to ~~53.5%~~ 52.9 of narrow range span at 100% of nominal load
16. Undervoltage-Reactor Coolant Pumps	≥ 4830 volts-each bus	≥ ~~4761~~ 4744 volts-each bus
17. Underfrequency-Reactor Coolant Pumps	≥ 57 Hz - each bus	≥ ~~56.0~~ 56.9 Hz - each bus
18. Turbine Trip		
a. Low Trip System Pressure	≥ 45 psig	≥ 43 psig
b. Turbine Stop Valve Closure	≥ 1% open	≥ 1% open
19. Safety Injection Input from ESF	N.A.	N.A.

TABLE 2.2-1 (Continued)

TABLE NOTATIONS (Continued)

NOTE 1: (continued)

τ_6 = Time constant utilized in the measured T_{avg} lag compensator, τ_6 = 2 s,

T' $\leq$ 588.2°F (Nominal T_{avg} at RATED THERMAL POWER),

K_3 = 0.000647/psig,

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 detectors of the power range neutron ion chambers; with gains to be selected based on measured instrument response during plant startup tests such that:

(i) for $q_t - q_b$ between -32% and +10% $f_1(\Delta I) = 0$ (where q_t and q_b are percent RATED THERMAL POWER in the top and bottom halves of the core respectively, and $q_t + q_b$ is total THERMAL POWER in percent of RATED THERMAL POWER);

(ii) for each percent that the magnitude of $(q_t - q_b)$ exceeds -32%, the ΔT Trip Setpoint shall be automatically reduced by 1.34% of its value at RATED THERMAL POWER up to 24.12%;

(iii) for each percent that the magnitude of $(q_t - q_b)$ exceeds +10%, the ΔT Trip Setpoint shall be automatically reduced by 1.22% of its value at RATED THERMAL POWER up to 30.5%.

NOTE 2: The channel's maximum Trip Setpoint shall not exceed its computed Trip Setpoint by more than 3.1%.

TABLE 2.2-1 (Continued)

TABLE NOTATIONS (Continued)

Note 3: (continued)

K_6 = 0.00126/°F for T > T" and K_6 = 0 for T ≤ T",

T = As defined in Note 1,

T" = Indicated T_{avg} at RATED THERMAL POWER (Calibration temperature for ΔT instrumentation, ≤ 588.2°F),

S = As defined in Note 1, and

$f_2(\Delta I)$ = 0 for all ΔI.

NOTE 4: The channel's maximum Trip Setpoint shall not exceed its computed Trip Setpoint by more than ~~2.0%~~.
3.2

Page 2-6 Interlock Setpoints

The interlock setpoints and allowable valves have been revised based on setpoint methodology calculations consistent with the Westinghouse methodology.

TABLE 2.2-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
20. Reactor Trip System Interlocks		
a. Intermediate Range Neutron Flux, P-6	$\geq 1 \times 10^{-10}$ amps	$\geq 6 \times 10^{-11}$ amps
b. Low Power Reactor Trips Block, P-7		
1) P-10 Input	10% of RATED THERMAL POWER	> ~~9%~~ 7.6, < ~~11%~~ 12.4 of RATED THERMAL POWER
2) P-13 Input	< 10% RTP Turbine Impulse Pressure Equivalent	< 11% RTP Turbine Impulse Pressure Equivalent
c. Power Range Neutron Flux, P-8	< 48% of RATED THERMAL POWER	< ~~49%~~ 50.4 of RATED THERMAL POWER
d. Power Range Neutron Flux, P-9	< 50% of RATED THERMAL POWER	< ~~51%~~ 52.4 of RATED THERMAL POWER
e. Power Range Neutron Flux, P-10	10% of RATED THERMAL POWER	> ~~9%~~ 7.6, < ~~11%~~ 12.4 of RATED THERMAL POWER
f. Turbine Impulse Chamber Pressure, P-13	< 10% RTP Turbine Impulse Pressure Equivalent	< 11% RTP Turbine Impulse Pressure Equivalent
21. Reactor Trip Breakers	N.A.	N.A.
22. Automatic Trip and Interlock Logic	N.A.	N.A.

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P-13

T.S. PAGE 2-6, 3/4 3-4, 3/4 3-12, 3/4 3-13

Technical Specification 3.3.1 (Table 3.3-1) item 20.f requires via ACTION statement 8 that the plant enter specification 3.0.3 (which requires initiating plant shutdown in 1 hour) if both channels of P-13 fail. TVA believes this is too restrictive since the only function P-13 has is a totally redundant input to P-7. Since that input is covered under item 20.b, item 20.f should be deleted. Thus if we lose both channels of P-13 we would not be forced to shutdown unless we also lost 3 channels of P-10 since this would cause us to lose P-7. Then and only then would specification 3.0.3 be appropriate since the "at power" trips (low RC loop flow, RCP underfrequency and undervoltage, PRZ press low, and PRZ level high) would be defeated.

TABLE 2.2-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
20. Reactor Trip System Interlocks		
a. Intermediate Range Neutron Flux, P-6	$\geq 1 \times 10^{-10}$ amps	$\geq 6 \times 10^{-11}$ amps
b. Low Power Reactor Trips Block, P-7		
1) P-10 Input	10% of RATED THERMAL POWER	> 9%, < 11% of RATED THERMAL POWER
2) P-13 Input	< 10% RTP Turbine Impulse Pressure Equivalent	< 11% RTP Turbine Impulse Pressure Equivalent
c. Power Range Neutron Flux, P-8	< 48% of RATED THERMAL POWER	< 49% of RATED THERMAL POWER
d. Power Range Neutron Flux, P-9	< 50% of RATED THERMAL POWER	< 51% of RATED THERMAL POWER
e. Power Range Neutron Flux, P-10	10% of RATED THERMAL POWER	> 9%, < 11% of RATED THERMAL POWER
~~f. Turbine Impulse Chamber Pressure, P-13~~	~~< 10% RTP Turbine Impulse Pressure Equivalent~~	~~< 11% RTP Turbine Impulse Pressure Equivalent~~
21. Reactor Trip Breakers	N.A.	N.A.
22. Automatic Trip and Interlock Logic	N.A.	N.A.

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TABLE 3.3-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
18. Turbine Trip					
a. Low Fluid Oil Pressure	3	2	2	1####	7#
b. Turbine Stop Valve Closure	4	4	4	1####	11#
19. Safety Injection Input from ESF	2	1	2	1, 2	9
20. Reactor Trip System Interlocks					
a. Intermediate Range Neutron Flux, P-6	2	1	2	2##	8
b. Low Power Reactor Trips Block, P-7					
P-10 Input	4	2	3	1	8
or					
P-13 Input (Turbine Impulse Chamber)	2	1	2	1	8
c. Power Range Neutron Flux, P-8	4	2	3	1	8
d. Power Range Neutron Flux, P-9	4	2	3	1	8
e. Power Range Neutron Flux, P-10	4	3 ~~2~~	4 ~~3~~	1, ~~2~~	12 ~~8~~
~~f. Turbine Impulse Chamber Pressure, P-13~~	~~2~~	~~1~~	~~2~~	~~1~~	~~8~~

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TABLE 4.3-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

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

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TABLE 4.3-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	ANALOG CHANNEL OPERATIONAL TEST	TRIP ACTUATING DEVICE OPERATIONAL TEST	ACTUATION LOGIC TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
20. Reactor Trip System Interlocks (Continued)						
d. Power Range Neutron Flux, P-9	N.A.	R (4)	M (8)	N.A.	N.A.	1
e. Power Range Neutron Flux, P-10	N.A.	R (4)	M (8)	N.A.	N.A.	1, 2
~~f. Turbine Impulse Chamber Pressure, P-13~~	~~N.A.~~	~~R~~	~~M (8)~~	~~N.A.~~	~~N.A.~~	~~1~~
21. Reactor Trip Breaker	N.A.	N.A.	N.A.	M (7,11)	N.A.	1,2,3*,4*,5*
22. Automatic Trip and Interlock Logic	N.A.	N.A.	N.A.	N.A.	M (7)	1,2,3*,4*,5*

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NRC Question

23: (Bases) 2.1. Reactor Coolant System Pressure (page B 2-2)

This section states that the entire RCS is hydrotested at 3107 psig which is 125 percent of the system's design pressure. The staff notes that 125% of design pressure is 1.25 times 2500 psia = 3125 psia - 15 psia = 3110 psig.

The staff notes that this issue involves an insignificant difference of 3 psi. However, we recommend that this editorial change be made.

Response

The technical specification value specified for the RCS hydrostatic test pressure should be 3107 psig.

TVA has reviewed its records for the initial cold hydrostatic pressure test. The minimum acceptable test pressure was listed as 3107 psig. The test has been completed with an acceptance criteria on pressure of 3107 psig. The technical specification value must not be different than the acceptance criteria of a test that is part of the quality assurance records for the plant.

Further, TVA disagrees with the method used to calculate value of 3110 psig. The American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel (B&PV) Codes specify that the hydrostatic tests be performed at 125 percent of design pressure. The design documents for the reactor pressure vessel list the design pressure as 2485 psig. Standard code convention is to multiply 2485 psig times 1.25 to get a pressure of 3107 psig. The purpose of the test is to ensure that the vessel can withstand the appropriate differential pressure. Since the atmospheric pressure is relatively constant and it is the pressure outside the vessel, gauge pressure is the appropriate pressure to use for the test.

2.1.2 REACTOR COOLANT SYSTEM PRESSURE

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

The reactor vessel and pressurizer are designed to Section III of the ASME Code for Nuclear Power Plants which permits a maximum transient pressure of 110% (2735 psig) of design pressure. The Reactor Coolant System piping, valves, and fittings are designed to ASME Section III 1971 Edition, which permits a maximum transient pressure of 120% (2985 psig) of component design pressure. The Safety Limit of 2735 psig is therefore consistent with the design criteria and associated code requirements.

The entire Reactor Coolant System is hydrotested at greater than or equal to 125% (~~3110~~ psig) of design pressure, to demonstrate integrity prior to initial operation. 3107

AUG 7 1984

TABLE 5.7-1

COMPONENT CYCLIC OR TRANSIENT LIMITS

COMPONENT	CYCLIC OR TRANSIENT LIMIT	DESIGN CYCLE OR TRANSIENT
Reactor Coolant System	200 heatup cycles at ≤ 100°F/hr and 200 cooldown cycles at ≤ 100°F/hr.	Heatup cycle - T_{avg} from ≤ 200°F to ≥ 550°F. Cooldown cycle - T_{avg} from ≥ 550°F to ≤ 200°F.
	200 pressurizer cooldown cycles at ≤ 200°F/hr.	Pressurizer cooldown cycle temperatures from ≥ 650°F to ≤ 200°F.
	80 loss of load cycles, without immediate Turbine or Reactor trip.	≥ 15% of RATED THERMAL POWER to 0% of RATED THERMAL POWER.
	40 cycles of loss of offsite A.C. electrical power.	Loss of offsite A.C. electrical ESF Electrical System.
	80 cycles of loss of flow in one reactor coolant loop.	Loss of only one reactor coolant pump.
	400 Reactor trip cycles.	100% to 0% of RATED THERMAL POWER.
	10 auxiliary spray actuation cycles.	Spray water temperature differential > 320°F.
	50 leak tests.	Pressurized to ≥ ~~2485~~ psig.
	5 hydrostatic pressure tests.	Pressurized to ≥ ~~3100~~ 3107 psig.
Secondary Coolant System	5 hydrostatic pressure tests.	Pressurized to ≥ 1350 psig.

FINAL DRAFT

Page B2-6 Bases for Steam and Feedwater Flow Mismatch Channels

The allowable values rather than the trip setpoints for low steam generator water level were incorrectly inserted in the bases for this trip channel. The correct values are now provided.

LIMITING SAFETY SYSTEM SETTINGS

BASES

On increasing power above P-7 (a power level of approximately 10% of RATED THERMAL POWER or a turbine impulse chamber pressure at approximately 10% of full power equivalent), an automatic Reactor trip will occur if the flow in more than one loop drops below 90% of nominal full loop flow. Above P-8 (a power level of approximately 48% of RATED THERMAL POWER) an automatic Reactor trip will occur if the flow in any single loop drops below 90% of nominal full loop flow. Conversely on decreasing power between P-8 and the P-7 an automatic Reactor trip will occur on loss of flow in more than one loop and below P-7 the trip function is automatically blocked.

Steam Generator Water Level

The Steam Generator Water Level Low-Low trip protects the reactor from loss of heat sink in the event of a sustained steam/feedwater flow mismatch resulting from loss of normal feedwater. The specified Setpoint provides allowances for starting delays of the Auxiliary Feedwater System.

Steam/Feedwater Flow Mismatch and Low Steam Generator Water Level

The steam/feedwater flow mismatch in coincidence with a Steam Generator Low Water Level trip is not used in the transient and accident analyses but is included in Table 2.2-1 to ensure the functional capability of the specified trip settings and thereby enhance the overall reliability of the Reactor Trip System. This trip is redundant to the Steam Generator Water Level Low-Low trip. The steam/feedwater flow mismatch portion of this trip is activated 17 when the steam flow exceeds the feedwater flow by greater than ~~or equal~~ to 1.51×10^6 lbs/hour. The steam generator low water ~~level~~ portion of the trip is activated when the water level drops below ~~15.6%~~ of narrow range span between 0 and 35% load, increasing to ~~53.5%~~ of narrow range span at 100% of nominal load. These trip values include sufficient allowance in excess of normal operating values to preclude spurious trips but will initiate a Reactor trip before the steam generators are dry. Therefore, the required capacity and starting time requirements of the auxiliary feedwater pumps are reduced and the resulting thermal transient on the Reactor Coolant System and steam generators is minimized. 54.9

Undervoltage and Underfrequency - Reactor Coolant Pump Busses

The Undervoltage and Underfrequency Reactor Coolant Pump Bus trips provide core protection against DNB as a result of complete loss of forced coolant flow. The specified Setpoints assure a Reactor trip signal is generated before the Low Flow Trip Setpoint is reached. Time delays are incorporated in the Underfrequency and Undervoltage trips to prevent spurious Reactor trips from momentary electrical power transients. For undervoltage, the delay is set so that the time required for a signal to reach the Reactor trip breakers

Page B2-7 Undervoltage Time Delay

In reviewing the bases for the reactor coolant pump bus underwater trip, it was determined that the delay time of 0.9 seconds is in error. This value was the delay time used for Sequoyah Nuclear Plant. The correct value for Watts Bar is 1.2 seconds.

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BASES

following the simultaneous trip of two or more reactor coolant pump bus circuit breakers shall not exceed ~~0.9~~ 1.27 seconds. For underfrequency, the delay is set so that the time required for a signal to reach the Reactor trip breakers after the Underfrequency Trip Setpoint is reached shall not exceed 0.3 second. On decreasing power the Undervoltage and Underfrequency Reactor Coolant Pump Bus trips are automatically blocked by P-7 (a power level of approximately 10% of RATED THERMAL POWER with a turbine impulse chamber pressure at approximately 10% of full power equivalent); and on increasing power, reinstated automatically by P-7.

Turbine Trip

A Turbine Trip initiates a Reactor trip. On decreasing power the Reactor trip on Turbine trip is automatically blocked by P-9 (a power range channel level of approximately 50% of RATED THERMAL POWER); and on increasing power, reinstated automatically by P-9.

Safety Injection Input from ESF

If a Reactor trip has not already been generated by the Reactor Trip System instrumentation, the ESF automatic actuation logic channels will initiate a Reactor trip upon any signal which initiates a Safety Injection. The ESF instrumentation channels which initiate a Safety Injection signal are shown in Table 3.3-3.

Reactor Trip System Interlocks

The Reactor Trip System interlocks perform the following functions:

P-6 On increasing power P-6 allows the manual block of the Source Range Reactor trip and de-energizing of the high voltage to the detectors. On decreasing power, Source Range Level trips are automatically reactivated and high voltage restored;

P-7 On increasing power P-7 automatically enables Reactor trips on low flow in more than one reactor coolant loop, reactor coolant pump bus undervoltage and underfrequency, pressurizer low pressure and pressurizer high level. On decreasing power the above listed trips are automatically blocked;

3/4 1-9

Surveillance requirement 4.1.2.3.2 needs to be revised to permit realignment of charging pumps during periods of reactor coolant pump operation. Normal seal flow must be maintained. The proposed wording allows operation of both pumps with the normal charging and injection pathways isolated. Seal flow can be maintained. Both pumps must be operated for a period of time when switching pumps. The second pump must be started and allowed to stabilize before the first pump is stopped. This process ensures continuous reactor coolant pump seal flow. Pump switching is required for mainterance and test alignments. The proposed surveillance requirement meets the safety intent by minimizing the potential for reactor vessel over-pressurization while allowing necessary plant operations.

FINAL DRAFT

CHARGING PUMP - SHUTDOWN

LIMITING CONDITION FOR OPERATION

3.1.2.3 One charging pump in the boron injection flow path required by Specification 3.1.2.1 shall be OPERABLE and capable of being powered from an OPERABLE emergency power source.

APPLICABILITY: MODES 4, 5 and 6.

ACTION:

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

SURVEILLANCE REQUIREMENTS

4.1.2.3.1 The above required charging pump shall be demonstrated OPERABLE by verifying ~~that~~ a discharge pressure ~~across the pump~~ of greater than or equal to 2400 psig is developed when tested pursuant to Specification 4.0.5.

4.1.2.3.2 All charging pumps, excluding the above required OPERABLE pump, shall be demonstrated inoperable at least once per 31 days, except when the reactor vessel head is removed, by verifying that the pumps are in the pull-to-lock position ~~and~~ and/or the motor circuit breakers are tagged out, or the pump(s) is isolated from the RCS by a manually closed valve or by a motor-operated valve with the valve breaker tagged. Normal seal flow can be maintained at all times.

OCT 26 1984

A27 840530 005

GCW

400 Chestnut Street Tower II

May 30, 1984

Director of Nuclear Reactor Regulation
Attention: Ms. E. Adensam, Chief
Licensing Branch No. 4
Division of Licensing
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

Dear Ms. Adensam:

In the Matter of the Application of) Docket Nos. 50-390
Tennessee Valley Authority)

Please refer to (1) my letter to L. S. Rubenstein dated April 9, 1980 which provided information on the Sequoyah Nuclear Plant (SQN) unit 1 low power test program as requested by Supplement No. 1 to the SQN Safety Evaluation Report (NUREG-0011), and (2) H. R. Denton's letter to H. G. Parris dated July 10, 1980, which issued Amendment No. 4 to License No. DPR-77 (SQN unit 1) concerning the subject low power test program.

TVA plans to perform one type of natural circulation test several times during the Watts Bar Nuclear Plant (WBN) unit 1 startup test program for operator training.

The applicability of the Technical Specification (TS) safety limit, figure 2.1-1 of the TS, should be waived during performance of the natural circulation tests. This figure is based on four reactor coolant pumps in operation. During performance of the tests, no reactor coolant pumps will be in operation.

During performance of the tests, the overpower and overtemperature delta-T trip functions will be considered inoperable. These trip functions obtain temperature inputs from sensors located in the resistance temperature detector bypass loops. During natural circulation, the bypass loop flow will be extremely low causing the temperature indication to be in error and the response time characteristics to be slowed. The TS requirement 2.2.1, items 7 and 8, should be waived during performance of these tests.

TVA plans to isolate the Upper Head Injection (UHI) system during performance of these tests. This will be done to prevent inadvertent actuation of the system and the potential for economic damage to the reactor internals. The UHI system provides borated water to mitigate the consequences of a large loss of coolant accident. Evaluations done for the SQN natural circulation test program established that this system provides little or no benefit for accidents involving low power or decay heat levels. TS requirement 3.5.1.2 should be waived during performance of these tests.

Director of Nuclear Reactor Regulation May 30, 1984

Please ensure that the WBN unit 1 low power license contains the requested exemptions to the TS for the purpose of performing the natural circulation tests. By the previously referenced amendment to the SQN license, NRC granted similar exemptions that were requested by TVA.

If you have any questions concerning this matter, please get in touch with D. B. Ellis at FTS 858-2681.

Very truly yours,

TENNESSEE VALLEY AUTHORITY

L. M. Mills

L. M. Mills, Manager
Nuclear Licensing

Sworn to and subscribed before me
this 30th day of May 1984

Paulette H. White
Notary Public
My Commission Expires 9-5-84

cc: U.S. Nuclear Regulatory Commission
Region II
Attn: Mr. James P. O'Reilly Administrator
101 Marietta Street, NW, Suite 2900
Atlanta, Georgia 30303

RHS:DBE:LHB

cc: ARMS, 640 CST2-C
H. L. Abercrombie, 1750 CST2-C
J. W. Anderson, 255 SPB-K
E. A. Belvin, 109 MPB-M
T. G. Campbell, 1750 CST2-C
H. N. Culver, 249A HBB-K
G. W. Killian, 401 UBB-C (2)
J. A. Raulston, W10C126 C-K
H. S. Sanger, Jr., E11B33 C-K
M. Shymlock, Watts Bar-NRC
F. A. Szczepanski, 220 401B-C

COORDINATED: Memo from Coffey to Mills dated 5/3/84 (L33 840427 818).

8409 340830 008

400 Chestnut Street Tower II

August 30, 1984

Director of Nuclear Reactor Regulation
Attention: Ms. E. Adensam, Chief
Licensing Branch No. 4
Division of Licensing
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

Dear Ms. Adensam:

In the Matter of the Application of) Docket Nos. 50-390
Tennessee Valley Authority) 50-391

Please refer to TVA's letter dated June 19, 1984 which transmitted various comments/proposed modifications to the proof and review version of the Watts Bar Nuclear Plant (WBN) unit 1 Technical Specifications.

Included in the referenced transmittal was a proposed modification revising the allowable Technical Specification limits for Reactor Coolant System (RCS) total flow rate and flow measurement uncertainty from 403600 gpm and 3.5 percent to 396000 gpm and 1.5 percent respectively. At the NRC's request, a conference call was held between TVA, Westinghouse Electric Corporation (W), and NRC representatives on July 13, 1984 to discuss the subject proposed modification. During this conference call, the principal NRC reviewer on this matter indicated that TVA's proposal to limit the RCS flow measurement uncertainty value to 1.5 percent was substantially lower than the Technical Specification limits developed for most of the recently licensed W PWRs. It was further indicated that TVA would need to provide additional information in the form of an analytical report to support an RCS flow measurement uncertainty of less than 2.1 percent.

W has modified, for applicability to WBN, an existing generic report addressing RCS flow measurement uncertainties. The generic report was modified to account for differences in the WBN Rosemount RTDs from those that were used in the development of the generic report. The W analysis yielded a 1.5-percent calorimetric uncertainty and a .2 percent elbow tap normalization uncertainty. In addition to the 1.5 percent calorimetric and .2 percent elbow tap normalization uncertainties, a .1 percent feedwater venturi fouling uncertainty should also be applied thus yielding a RCS flow measurement uncertainty of 1.8 percent.

To allow for scheduling conflicts and plant availability during startup, TVA plans to calibrate the process components 14 days before and after the required Technical Specification channel test (Surveillance Requirement 4.2.3.4).

Enclosed is a copy of both the proprietary and nonproprietary versions of "Westinghouse Report on RCS Flow Uncertainties with the Use of Rosemount RTDs" (Enclosure 1). In addition, we have enclosed the W authorization letter CAW-84-79 and an accompanying affidavit (Enclosure 1).

As this submittal contains information proprietary to W, it is supported by an affidavit signed by W, the owner of the information. The affidavit sets forth the basis on which the information may be withheld from public disclosure by the Commission and addresses with specificity the considerations listed in paragraph (b)(4) of Section 2.790 of the Commission's regulations.

Accordingly, it is respectfully requested that the information which is proprietary to W be withheld from public disclosure in accordance with 10 CFR Section 2.790 of the Commission's regulations. Correspondence with respect to the proprietary aspects of the Application for Withholding or the supporting Westinghouse affidavit should reference CAW-84-72 and should be addressed to R. A. Wiesemann, Manager Regulatory and Legislative Affairs, Westinghouse Electric Corporation, P.O. Box 355, Pittsburgh, Pennsylvania 15230.

Also enclosed are proposed modifications to the unit 1 Technical Specifications consistent with the discussions above (Enclosure 2). Technical Specification Figure 3.2-3, "RCS Total Flow Rate Versus R", will need to be revised and will be forwarded in the near future.

If you have any questions concerning this matter, please get in touch with D. R. Ellis at FTS 858-2681.

Very truly yours,

TENNESSEE VALLEY AUTHORITY

L. M. Mills

L. M. Mills, Manager
Nuclear Licensing

Sworn to and subscribed before me
this 30th day of August 1984

Paulette H. White
Notary Public
My Commission Expires 9-5-84

Enclosures (2)
cc: U.S. Nuclear Regulatory Commission
Region II
Attn: Mr. James P. O'Reilly Administrator
101 Marietta Street, NW, Suite 2900
Atlanta, Georgia 30323

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

LIMITING CONDITION FOR OPERATION

3.2.3 The combination of indicated Reactor Coolant System (RCS) total flow rate and R shall be maintained within the region of allowable operation shown on Figure 3.2-3 for four loop operation.

Where:

a. $R = \dfrac{F^N_{\Delta H}}{1.49\,[1.0 + 0.2\,(1.0 - P)]}$,

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

c. $F^N_{\Delta H}$ = Measured values of $F^N_{\Delta H}$ obtained by using the movable incore detectors to obtain a power distribution map. The measured values of $F^N_{\Delta H}$ shall be used to calculate R since Figure 3.2-3 includes penalties for undetected feedwater venturi fouling of 0.1% and measurement uncertainties of ~~2.1%~~ 1.7% for flow and 4% for incore measurement of $F^N_{\Delta H}$.

APPLICABILITY: MODE 1.

ACTION:

With the combination of RCS total flow rate and R outside the region of acceptable operation shown on Figure 3.2-3:

a. Within 2 hours either:

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

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

AUG 27 1984

ACTION (Continued)

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

c. Identify and correct the cause of the out-of-limit condition prior to increasing THERMAL POWER above the reduced THERMAL POWER limit required by ACTION a.2. and/or b. above; subsequent POWER OPERATION may proceed provided that the combination of R and indicated RCS total flow rate are demonstrated, through incore flux mapping and RCS total flow rate comparison, to be within the region of acceptable operation shown on Figure 3.2-3 prior to exceeding the following THERMAL POWER levels:

1. A nominal 50% of RATED THERMAL POWER,
2. A nominal 75% of RATED THERMAL POWER, and
3. Within 24 hours of attaining greater than or equal to 95% of RATED THERMAL POWER.

SURVEILLANCE REQUIREMENTS

4.2.3.1 The provisions of Specification 4.0.4 are not applicable.

4.2.3.2 The combination of indicated RCS total flow rate and R shall be determined to be within the region of acceptable operation of Figure 3.2-3:

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

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

4.2.3.3 The indicated RCS total flow rate shall be verified to be within the region of acceptable operation of Figure 3.2-3 at least once per 12 hours when the most recently obtained values of R obtained per Specification 4.2.3.2, are assumed to exist.

4.2.3.4 The RCS total flow rate indicators shall be subjected to a CHANNEL CALIBRATION at least once per 18 months. The measurement instrumentation shall be calibrated within ~~7~~ 14 days prior to performance of the calorimetric flow measurement.

4.2.3.5 The RCS total flow rate shall be determined by precision heat balance measurement at least once per 18 months.

HEAT FLUX HOT CHANNEL FACTOR, and RCS FLOW RATE AND NUCLEAR ENTHALPY RISE HOT CHANNEL FACTOR (Continued)

When RCS flow rate and $F^N_{\Delta H}$ are measured, no additional allowances are necessary prior to comparison with the limit of Figure 3.2-3. Measurement errors of ~~2.1%~~ 1.7% for RCS total flow rate and 4% for $F^N_{\Delta H}$ have been allowed for in determination of the design DNBR value.

The 12-hour periodic surveillance of indicated RCS flow is sufficient to detect only flow degradation which could lead to operation outside the acceptable region of operation shown on Figure 3.2-3.

3/4.2.4 QUADRANT POWER TILT RATIO

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

The limit of 1.02, at which corrective action is required, provides DNB and linear heat generation rate protection with x-y plane power tilts. A limit of 1.02 was selected to provide an allowance for the uncertainty associated with the indicated power tilt.

The 2-hour time allowance for operation with a tilt condition greater than 1.02 but less than 1.09 is provided to allow identification and correction of a dropped or misaligned control rod. In the event such action does not correct the tilt, the margin for uncertainty on F_Q is reinstated by reducing the maximum allowed power by 3% for each percent of tilt in excess of 1.

For purposes of monitoring QUADRANT POWER TILT RATIO when one excore detector is inoperable, the moveable incore detectors are used to confirm that the normalized symmetric power distribution is consistent with the QUADRANT POWER TILT RATIO. The incore detector monitoring is done with a full incore flux map or two sets of four symmetric thimbles. The two sets of four symmetric thimbles is a unique set of eight detector locations. These locations are C-8, E-5, E-11, H-3, H-13, L-5, L-11, N-8.

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 throughout each analyzed transient. The indicated T_{avg} value of 593°F and the indicated pressurizer pressure value of 2220 psig correspond to analytical limits of 595°F and 2205 psig respectively, with allowance for measurement uncertainty.

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.

Page 3/4 2-15 DNB Parameters

The limits for pressurizer pressure and average reactor coolant system temperature have been adjusted to account for indicator loop inaccuracy.

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TABLE 3.2-1

DNB PARAMETERS

PARAMETER	LIMITS Four Loops in Operation
Indicated Reactor Coolant System T_{avg}	≤ ~~(593)°F~~ 592.2°F
Indicated Pressurizer Pressure	≥ (~~2220~~) psig* 2217

THIS PAGE OPEN PENDING RECEIPT OF INFORMATION FROM THE APPLICANT

*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.

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HEAT FLUX HOT CHANNEL FACTOR, and RCS FLOW RATE AND NUCLEAR ENTHALPY RISE HOT CHANNEL FACTOR (Continued)

When RCS flow rate and $F^N_{\Delta H}$ are measured, no additional allowances are necessary prior to comparison with the limit of Figure 3.2-3. Measurement errors of 2.1% for RCS total flow rate and 4% for $F^N_{\Delta H}$ have been allowed for in determination of the design DNBR value.

The 12-hour periodic surveillance of indicated RCS flow is sufficient to detect only flow degradation which could lead to operation outside the acceptable region of operation shown on Figure 3.2-3.

3/4.2.4 QUADRANT POWER TILT RATIO

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

The limit of 1.02, at which corrective action is required, provides DNB and linear heat generation rate protection with x-y plane power tilts. A limit of 1.02 was selected to provide an allowance for the uncertainty associated with the indicated power tilt.

The 2-hour time allowance for operation with a tilt condition greater than 1.02 but less than 1.09 is provided to allow identification and correction of a dropped or misaligned control rod. In the event such action does not correct the tilt, the margin for uncertainty on F_Q is reinstated by reducing the maximum allowed power by 3% for each percent of tilt in excess of 1.

For purposes of monitoring QUADRANT POWER TILT RATIO when one excore detector is inoperable, the moveable incore detectors are used to confirm that the normalized symmetric power distribution is consistent with the QUADRANT POWER TILT RATIO. The incore detector monitoring is done with a full incore flux map or two sets of four symmetric thimbles. The two sets of four symmetric thimbles is a unique set of eight detector locations. These locations are C-8, E-5, E-11, H-3, H-13, L-5, L-11, N-8.

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 throughout each analyzed transient. The indicated T_{avg} value of ~~593°F~~ 592.2°F and the indicated pressurizer pressure value of ~~2220~~ 2217 psig correspond to analytical limits of 59~~5~~6°F and 2205 psig respectively, with allowance for measurement uncertainty. C4

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.

NRC Question

2. Reactor Trip Instrumentation, Table 3.3-1 (page 3/4 3-2)

b. Item 20, the minimum channels operable for interlock P-10 for Mode 1 conflicts with FSAR Section 7.2.1.1.2. That is, when coming down in power it takes 3 out of 4 P-10 channels to reinstate the intermediate range high neutron flux trip and the low power range neutron flux trip. Item 20 shows 2 out of 4.

Response

Reference: Westinghouse SSPS drawing 1082H70 sheets 1 and 2 for Watts Bar (Attached).

From a safety standpoint, P-10 does two functions: (1) provides input to P-7 which Auto Enables the "At Power" Reactor Trips on 2/4 logic above setpoint -10 percent, and (2) Auto Enables the "Low Power" Reactor Trips (including Source Range high flux trip coincident w/P-6) on 3/4 logic below setpoint - 10 percent . Additionally, above P-10 a manual block of the "Low Power" Reactor Trips can be performed, however, this does not serve any safety function.

It should be noted that the bistables for P-10 have an energized output below the setpoint and switch when above the setpoint (i.e., to Auto Enable the "Low Power" Trips 3 bistables must be energized).

The way the Technical Specifications are currently written the input to P-7 is covered appropriately under P-7 functional unit 20.b. However, the Auto Enable of the "Low Power" Reactor Trips is not adequately covered. See the attached marked up Technical Specification pages for the required changes discussed below.

Technical Specifications - Changes

Table 3.3-1 Functional Unit 20.e (TS page 3/4 3-4)

CHANNELS TO TRIP should be 3, not 2. Three bistables must be energized to Auto Enable the "Low Power" Reactor Trips.

Table 3.3-1 Functional Unit 20.e and ACTION STATEMENT 12 (TS page 3/4 3-4 and TS page 3/4 3-8)

MINIMUM CHANNELS OPERABLE should be 4, not 3. Three channels are required to Auto Enable, thus 4 must be OPERABLE to meet single failure criteria. ACTION STATEMENT 12 has been added to reflect appropriate actions to different conditions. With less than 4 channels OPERABLE and the "Low Power" Reactor Trips blocked a plant shutdown below the P-10 setpoint (10 percent) is not warranted since the capability to enable the "Low Power" Reactor Trips may be lost. Since the P-10 bistables must be energized to enable the "Low Power" Reactor Trips, removing power from the bistables will not reinstate the trips. With less than 4 channels OPERABLE and the "Low Power" Reactor Trips not blocked, any P-10 failure will not block the "Low Power" Reactor Trips since it also takes coincident manual blocking (4 separate handswitches) to defeat them. Thus, the appropriate action is to restore the inoperable channels to OPERABLE status before blocking the "Low Power" Reactor Trip.

Table 3.3-1 Functional Unit 20.e (TS page 3/4 3-4) and Table 4.3-1 Functional unit 20.e (TS page 3/4 3-13)

APPLICABLE MODES should have mode 2 deleted. There is no consequence of being in mode 2 with P-10 operable. The Auto Enable of the "Low Power" Reactor Trips and the input to P-7 will take place at 10-percent Reactor power which is mode 1. And, as discussed above, the "Low Power" Reactor Trips once enabled cannot be blocked without manual action. A failure which would cause a P-10 input to P-7 in modes 2 and below could only enable the "At Power" Reactor Trips and thus has no adverse safety effect. Any P-10 malfunction that could make the Source Range detectors inoperable in mode 2 and below would be readily detectable via MCR indications and alarms and would be handled in accordance with Limiting Condition for Operation 3.3.1 (item 6 table 3.3-1) covering the Source Range detectors.

Note: A copy of the logic prints were transmitted to the NRC in a January 3, 1985, memo from J. A. Domer to E. Adensam.

TABLE 3.3-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
18. Turbine Trip					
a. Low Fluid Oil Pressure	3	2	2	1####	7#
b. Turbine Stop Valve Closure	4	4	4	1####	11#
19. Safety Injection Input from ESF	2	1	2	1, 2	9
20. Reactor Trip System Interlocks					
a. Intermediate Range Neutron Flux, P-6	2	1	2	2##	8
b. Low Power Reactor Trips Block, P-7					
P-10 Input	4	2	3	1	8
or					
P-13 Input	2	1	2	1	8
c. Power Range Neutron Flux, P-8	4	2	3	1	8
d. Power Range Neutron Flux, P-9	4	2	3	1	8
e. Power Range Neutron Flux, P-10	4	~~2~~ 3	~~3~~ 4	~~1, 2~~ 1	~~8~~ 12
f. Turbine Impulse Chamber Pressure, P-13	2	1	2	1	8

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TABLE 3.3-1 (Continued)

ACTION STATEMENTS (Continued)

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

ACTION 10 - With the number of OPERABLE channels one less than the Minimum Channels OPERABLE requirement, restore the inoperable channel to OPERABLE status within 48 hours or open the Reactor trip breakers within the next hour.

ACTION 11 - With the number of OPERABLE channels less than the Minimum Channels OPERABLE requirement, restore the inoperable channel to OPERABLE status within 48 hours or reduce power to below 50% RATED THERMAL POWER within the next 6 hours.

ACTION 12 - With the number of OPERABLE channels less than the Minimum Channels OPERABLE requirement and

1) With the "Low Power" Reactor Trips blocked, immediately restore the inoperable channels to OPERABLE status.

or

2) With the "Low Power" Reactor Trips not blocked, restore the inoperable channels to OPERABLE status prior to blocking the "Low Power" Reactor Trips.

The provisions of Specification 3.0.3 are not applicable.

TABLE 4.3-1 (Continued)

REACTOR TRIP SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	ANALOG CHANNEL OPERATIONAL TEST	TRIP ACTUATING DEVICE OPERATIONAL TEST	ACTUATION LOGIC TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
20. Reactor Trip System Interlocks (Continued)						
d. Power Range Neutron Flux, P-9	N.A.	R (4)	M (8)	N.A.	N.A.	1
e. Power Range Neutron Flux, P-10	N.A.	R (4)	M (8)	N.A.	N.A.	~~1, 2~~ 1
f. Turbine Impulse Chamber Pressure, P-13	N.A.	R	M (8)	N.A.	N.A.	1
21. Reactor Trip Breaker	N.A.	N.A.	N.A.	M (7,11)	N.A.	1,2,3*,4*,5*
22. Automatic Trip and Interlock Logic	N.A.	N.A.	N.A.	N.A.	M (7)	1,2,3*,4*,5*

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3/4 3-17, 3/4 3-20, 3/4 3-21, and 3/4 3-25

TVA has proposed that the action statement for certain portions of the auxiliary feedwater and containment spray instrumentation be revised to be consistent with the action statements associated with the mechanical equipment. Each auxiliary feedwater pump has a manual start switch and three pressure switches for suction transfer. An inoperable switch affects one and only one pump. The action statements should be consistent with those for inoperable pump. Having different actions for equipment inoperability leads to interpretation problems and a lack of confidence in the bases for the specifications. The same logic applies for the manual switches for the containment spray pumps.

TABLE 3.3-3 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
1. Safety Injection (Reactor Trip, Turbine Trip, Feedwater Isolation, Control Room Isolation, Start Diesel Generators, Component Cooling Water, and Essential Raw Cooling Water) (Continued)					
f. Steam Flow in Two Steam Lines-High	2/steam line	1/steam line any 2 steam lines	1/steam line	1, 2, 3###	15*
Coincident With Either					
T_{avg}-Low-Low	4 (1 T_{avg}/loop)	2	3	1, 2, 3###	15*
Or					
Steam Line Pressure-Low	4 (1 pressure/) loop)	2	3	1, 2, 3###	15*
2. Containment Spray					
a. Manual Initiation	2 pair	1 pair operated simultaneously	2 pair	1, 2, 3, 4	~~18~~ 26
b. Automatic Actuation Logic and Actuation Relays	2	1	2	1, 2, 3, 4	14

TABLE 3.3-3 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
5. Turbine Trip & Feedwater Isolation					
a. Automatic Actuation Logic and Actuation Relay	2	1	2	1, 2	23
b. Steam Generator Water Level--High-High	3/stm. gen.	2/stm. gen. in any operating stm. gen.	2/stm. gen. in each operating stm. gen.	1, 2	15*
6. Auxiliary Feedwater					
a. Manual Initiation	2	1	2	1, 2, 3	~~21~~ 25
b. Automatic Actuation Logic and Actuation Relays	2	1	2	1, 2, 3	20

TABLE 3.3-3 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
6. Auxiliary Feedwater (Continued)					
c. Stm. Gen. Water Level-Low-Low					
1) Start Motor-Driven Pumps	3/stm. gen.	2/stm. gen. in any operating stm. gen.	2/stm. gen. in each operating stm. gen.	1, 2, 3	15*
2) Start Turbine-Driven Pump	3/stm. gen.	2/stm. gen. in any 2 operating stm. gen.	2/stm. gen. in each operating stm. gen.	1, 2, 3	15*
d. Safety Injection - Start Motor-Driven Pumps and Turbine-Driven Pump	See Item 1. above for all Safety Injection initiating functions and requirements.				
e. Loss-of-Offsite Power - Start Motor-Driven Pumps and Turbine-Driven Pump	2/shutdown board	1/shutdown board	2/shutdown board	1, 2, 3	21*
f. Trip of All Main Feedwater Pumps - Start Motor-Driven Pumps and Turbine-Driven Pump	2	2	2	1, 2	24*
g. Auxiliary Feedwater Suction Pressure - Low	3/pump	2/pump	2/pump	1, 2, 3	~~21~~* 25

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TABLE 3.3-3 (Continued)

ACTION STATEMENTS (Continued)

ACTION 18 - With the number of OPERABLE channels one less than the Minimum Channels OPERABLE requirement, restore the inoperable channel to OPERABLE status within 48 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

ACTION 19 - 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.

ACTION 20 - With the number of OPERABLE Channels one less than the Minimum Channels OPERABLE requirement, be in at least HOT STANDBY within 6 hours and in at least HOT SHUTDOWN within the following 6 hours; however, one channel may be bypassed for up to 2 hours for surveillance testing per Specification 4.3.2.1 provided the other channel is OPERABLE.

ACTION 21 - With the number of OPERABLE channels one less than the Total Number of Channels, restore the inoperable channel to OPERABLE status within 48 hours or be in at least HOT STANDBY within 6 hours and in at least HOT SHUTDOWN within the following 6 hours.

ACTION 22 - With the number of OPERABLE channels one less than the Total Number of Channels, restore the inoperable channel to OPERABLE status within 48 hours or declare the associated valve inoperable and take the ACTION required by Specification 3.7.1.5.

ACTION 23 - With the number of OPERABLE channels one less than the Minimum Channels OPERABLE requirement, be in at least HOT STANDBY within 6 hours; however one channel may be bypassed for up to 2 hours for surveillance testing per Specification 4.3.2.1 provided the other channel is OPERABLE.

restore the inoperable channel to OPERABLE status within 48 hours or

ACTION 24 - With the number of OPERABLE channels one less than the Minimum Channels OPERABLE requirement, be in at least HOT STANDBY ~~within~~ 6 hours.

ACTION 25 - With the number of OPERABLE channels less than the minimum channels OPERABLE requirement, comply with the appropriate ACTION statement for Specification for Specification 3.7.1.2

ACTION 26 - With the number of OPERABLE channels one less than the Minimum Channels OPERABLE requirement, comply with the ACTION statement for Specification 3.6.2.

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Table 3.3-3 - Engineered Safety Feature Instrumentation

The circuits for the sump level-high and RWST level-low have been revised to trip when a channel is taken out of service. The action statements have been revised to reflect this design change.

TABLE 3.3-3 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
7. Automatic Switchover to Containment Sump					
a. Automatic Actuation Logic and Actuation Relays	2	1	2	1, 2, 3, 4	14
b. RWST Level - Low	4	2	3	1, 2, 3, 4	~~16~~ 15
Coincident With					
Containment Sump Level - High	4	2	3	1, 2, 3, 4	~~16~~ 15
And					
Safety Injection	See Item 1. above for Safety Injection initiating functions and requirements.				
8. 6.9 kV Shutdown Board					
a. Loss of Voltage					
1) Start Diesel Generator	2/Shutdown Board	1/Shutdown Board	2/Shutdown Board	1, 2, 3, 4	18*
2) Load Shedding	2/Shutdown Board	1/Shutdown Board	2/Shutdown Board	1, 2, 3, 4	18*
b. Degraded Voltage					
1) Voltage Sensor	3/Shutdown Board	2/Shutdown Board	2/Shutdown Board	1, 2, 3, 4	18*
2) Diesel Generator Start and Load Shedding Timer	2/Shutdown Board	1/Shutdown Board	1/Shutdown Board	1, 2, 3, 4	18*
3) Safety Injection Degraded Voltage Enable Timer	2/Shutdown Board	1/Shutdown Board	1/Shutdown Board	1, 2, 3, 4	18*

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3/4 3-23

The action statement for the P-14 interlock (item 9.d) should be revised to be consistent with the action statement for turbine trip and feedwater isolation on high steam generator levels (item 5.b). P-14 does not have a separate interlock status window in the control room. Action statement 19 cannot apply to TVA's design.

TABLE 3.3-3 (Continued)

ENGINEERED SAFETY FEATURE ACTUATION SYSTEM INSTRUMENTATION

FUNCTIONAL UNIT	TOTAL NO. OF CHANNELS	CHANNELS TO TRIP	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ACTION
9. Engineered Safety Features Actuation System Interlocks					
a. Pressurizer Pressure, P-11	3	2	2	1, 2, 3	19
b. Low-Low T_{avg}, P-12	4	2	3	1, 2, 3	19
c. Reactor Trip, P-4	2	2	2	1, 2, 3	21
d. Steam Generator Water Level, P-14	3/stm. gen.	2/stm. gen. in any operating stm. gen.	2/stm. gen. in each operating stm. gen.	1, 2	~~18~~15*

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Table 3.3-4 - Engineered Safety Feature Actuation Setpoints

The engineered safety feature actuation allowable valves have been revised to include the allowances provided in the setpoint study. The setpoint study has been previously submitted to NRC.

TABLE 3.3-4

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
1. Safety Injection (Reactor Trip, Turbine Trip, Feedwater Isolation, Control Room Isolation, Start Diesel Generators, Component Cooling Water, and Essential Raw Cooling Water)		
a. Manual Initiation	N.A.	N.A.
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
c. Containment Pressure--High	$\leq$ 1.54 psig	$\leq$ ~~1.7~~ 1.8 psig
d. Pressurizer Pressure--Low	$\geq$ 1870 psig	$\geq$ ~~1859~~ 1854 psig
e. Differential Pressure Between Steam Lines--High	$\leq$ 100 psi	$\leq$ ~~112~~ 127.6 psi
f. Steam Flow in Two Steam Lines--High	$<$ A function defined as follows: A Δp corresponding to 40% of full steam flow between 0% and 20% load and then a Δp increasing linearly to a Δp corresponding to 110% of full steam flow at full load	$<$ A function defined as follows: A Δp corresponding to ~~44%~~ 44.3 of full steam flow between 0% and 20% load and then a Δp increasing linearly to a Δp corresponding to ~~111.5%~~ 114.3 of full steam flow at full load
Coincident With		
Either		
T_{avg}--Low-Low	$\geq$ 550°F	$\geq$ ~~548~~ 547.3°F
Or		
Steam Line Pressure--Low	$\geq$ 675 psig	$\geq$ ~~655~~ 649 psig

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TABLE 3.3-4 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
2. Containment Spray		
a. Manual Initiation	N.A.	N.A.
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
c. Containment Pressure--High-High	≤ 2.81 psig	≤ ~~3.0~~ 3.1 psig
3. Containment Isolation		
a. Phase "A" Isolation		
1) Manual Initiation	N.A.	N.A.
2) Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
3) Safety Injection	See Item 1. above for all Safety Injection Trip Setpoints/ Allowable Values.	
b. Phase "B" Isolation		
1) Manual Initiation	N.A.	N.A.
2) Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
3) Containment Pressure--High-High	≤ 2.81 psig	≤ ~~3.0~~ 3.1 psig

TABLE 3.3-4 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
3. Containment Isolation (continued)		
c. Containment Ventilation Isolation		
1) Manual Initiation	N.A.	N.A.
2) Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
3) Safety Injection	See Item 1. above for all Safety Injection Trip Setpoints/ Allowable Values.	
4. Steam Line Isolation		
a. Manual Initiation	N.A.	N.A.
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
c. Containment Pressure--High-High	≤ 2.81 psig	≤ ~~3.0~~ 3.1 psig
d. Steam Flow in Two Steam Lines--High	< A function defined as follows: A Δp corresponding to 40% of full steam flow between 0% and 20% load and then a Δp increasing linearly to a Δp corresponding to 110% of full steam flow at full load	< A function defined as follows: A Δp corresponding to 44% of full steam flow between 0% and 20% load and then a Δp increasing linearly to a Δp corresponding to 111.5% of full steam flow at full load
Coincident With		
Either T_{avg}--Low-Low	≥ 550°F	≥ ~~548°F~~ ~~547.3~~ 547.3
Or Steam Line Pressure--Low	≥ 675 psig	≥ ~~655~~ 649 psig

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TABLE 3.3-4 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
5. Turbine Trip and Feedwater Isolation		
a. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
b. Steam Generator Water Level--High-High (P-14)	< 82.4% of narrow range instrument span each steam generator	< ~~84.2%~~ 84.4 of narrow range instrument span each steam generator
6. Auxiliary Feedwater		
a. Manual Initiation	N. A.	N. A.
b. Automatic Actuation Logic and Actuation Relays	N. A.	N. A.
c. Steam Generator Water Level-Low-Low Start Motor-Driven Pumps and Turbine-Driven Pump	> 17% of narrow range instrument span between 0 and 35% load increasing linearly to > 54.9% of narrow range span at 100% nominal load	> ~~15.6%~~ 15.0 of narrow range instrument span between 0 and 35% load increasing linearly to > ~~53.5%~~ 52.9 of narrow range span at 100% nominal load
d. Safety Injection Start Motor-Driven Pumps and Turbine-Driven Pump	See Item 1. above for all Safety Injection Trip Setpoints/Allowable Values.	
e. Loss-of-Offsite Power-Start Motor-Driven Pumps Start Turbine-Driven Pump		
1) Nominal Voltage Setpoint	~~4860~~ 4830 volts	~~4860~~ 4830 ± 97.2 volts
2) Relay Response Time	0.0 volt input to the inverse time relay with a 5 second time delay	0.0 volt input to the inverse time relay with a 5 ± 1 second time delay
f. Trip of All Main Feedwater Pumps - Start Motor-Driven Pumps and Turbine-Driven Pump	N.A.	N.A.

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TABLE 3.3-4 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
6. Auxiliary Feedwater (continued)		
g. Auxiliary Feedwater Suction Pressure-Low (Suction Transfer to ERCW)		
1) Supply Valve for Motor-Driven Pump	≥ ~~2.15~~ 1.70 psig	≥ ~~1.65~~ 0.95 psig
2) Supply Valve for Turbine-Driven Pump	≥ ~~13.1~~ 11.1 psig	≥ ~~12.1~~ 10.0 psig
7. Automatic Switchover To Containment Sump		
a. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
b. RWST Level - Low Coincident With	≥ 130" from tank base	≥ 126" from tank base
Containment Sump Level - High	≤ 30" above elev. 703'	≤ 32.5" above elev. 703'
And		
Safety Injection	See Item 1. above for all Safety Injection Trip Setpoints/ Allowable Values	
8. 6.9 kV Shutdown Board		
a. Loss of Voltage		
1) Start Diesel Generator		
a) Nominal Voltage Setpoint	~~4860~~ 4830 volts	~~4860~~ 4830 ± 97.2 volts
b) Relay Response Time	0.0 volt input to the inverse time relay with a 1.5 second time delay	0.0 volt input to the inverse time relay with a 1.5 ± 1.0 second time delay

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TABLE 3.3-4 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
8. 6.9 kV Shutdown Board (continued)		
2) Load Shedding		
a) Nominal Voltage Setpoint	4830 ~~4860~~ volts	4830 ~~4860~~ ± 97.2 volts
b) Relay Response Time	0.0 volts with a 5 second time delay	0.0 volts with 5 ± 1 second time delay
b. Degraded Voltage		
1) Voltage Sensor	6560 volts	6560 ± 33 volts
2) Diesel Generator Start and Load Shedding Timer	300 seconds	300 ± 30 seconds
3) Safety Injection Degraded Voltage Logic Enable Timer	10 seconds	10 ± 1 seconds
9. Engineered Safety Features Actuation System Interlocks		
a. Pressurizer Pressure, P-11	$\leq$ 1970 psig	$\leq$ 1980 psig
b. Low-Low T_{avg}, P-12, increasing / decreasing	$\geq$ 550°F / $\leq$ 550°F	$\leq$ 552°F / $\geq$ 548°F
c. Reactor Trip, P-4	N.A.	N.A.
d. Steam Generator Water Level, P-14	See Item 5. above for all Steam Generator Water Level-High-High Trip Setpoints and Allowable Values.	

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OLL

400 Chestnut Street Tower II

October 16, 1984

Director of Nuclear Reactor Regulation
Attention: Ms. E. Adensam, Chief
Licensing Branch No. 4
Division of Licensing
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555

Dear Ms. Adensam:

In the Matter of the Application of	)	Docket Nos. 50-390
Tennessee Valley Authority	)	50-391

Please refer to TVA's letter dated April 25, 1983 which, in accordance with the Watts Bar Nuclear Plant (WBN) Safety Evaluation Report Section 7.1.3.1, "Safety System Set Point Methodology" (confirmatory item 21), provided a summary of the analysis data used in establishing setpoints for the WBN balance-of-plant equipment.

Recent evaluations have determined that the data provided for the Auxiliary Feedwater pumps (suction pressure low) is no longer valid and requires revision. Enclosure 1 provides the revised data. Enclosure 2 provides corresponding revisions to the unit 1 draft Technical Specifications.

If you have any questions concerning this matter, please get in touch with D. B. Ellis at FTS 858-2681.

Very truly yours,

TENNESSEE VALLEY AUTHORITY

L. M. Mills

L. M. Mills, Manager
Nuclear Licensing

Sworn to and subscribed before me
this 16th day of Oct. 1984

Paulette H. White
Notary Public
My Commission Expires 8-24-88

Enclosures (2)
cc: U.S. Nuclear Regulatory Commission (Enclosures)
Region II
Attn: Mr. James P. O'Reilly Administrator
101 Marietta Street, NW, Suite 2900
Atlanta, Georgia 30323

ENCLOSURE 1

WATTS BAR NUCLEAR PLANT
SETPOINT METHODOLOGY DATA FOR BALANCE-OF-PLANT EQUIPMENT

AUXILIARY FEEDWATER PUMPS (SUCTION PRESSURE LOW)

REVISED RESPONSE

AUXILIARY FEEDWATER TURBINE-DRIVEN PUMP SUCTION PRESSURE LOW

Parameters (3)			Notes
PMA	=	--	
PEA	=	--	
SCA	=	1.0	(1)
SPE	=	--	
STE	=	0.5	(1)
SD	=	5.0	(1)
EA	=	--	
RCA	=	--	
RCSA	=	--	
RTE	=	--	
RD	=	--	
Safety Analysis Limit	=	9.2 lb/in^2g	(4) (5)
Allowable Value	=	10.0 lb/in^2g	(2) (5)
Trip Set Point	=	11.1 lb/in^2g	(2) (4) (5)
Total Allowance	=	10.6	(1)
Channel Statistical Allowance	=	6.0	(1)
Margin	=	4.6	(1)

(1) All values in percent of adjustable range (18 lb/in^2).
(2) As noted in Table 3.3-4 of draft Technical Specification.
(3) Parameters are defined in Westinghouse proprietary "Set Point Methodology Report" and are based on the switches procured by requisition No. 830616.
(4) From MEB calculation (MEB 840829 002).
(5) Based on time delay of 4 seconds or less, each timer.

AUXILIARY FEEDWATER MOTOR-DRIVEN PUMP SUCTION PRESSURE LOW

Parameters (3)			Notes
PMA	=	--	
PEA	=	--	
SCA	=	1.0	(1)
SPE	=	--	
STE	=	0.5	(1)
SD	=	0.0	(1) (5)
EA	=	10.0	(1)
RCA	=	--	
RCSA	=	--	
RTE	=	--	
RD	=	--	
Safety Analysis Limit	=	0.05 lb/in^2g	(4) (6)
Allowable Value	=	0.95 lb/in^2g	(2) (6)
Trip Set Point	=	1.70 lb/in^2g	(2) (4) (6)
Total Allowance	=	18.3	(1)
Channel Statistical Allowance	=	11.1	(1)
Margin	=	7.2	(1)

(1) All values in percent of adjustable range (9 lb/in^2).
(2) As noted in Table 3.3-4 of draft Technical Specification.
(3) Parameters are defined in Westinghouse proprietary "Set Point Methodology Report" and are based on the switches procured by requisition No. 830616.
(4) From MEB calculation (MEB 840829 002).
(5) Included in EA.
(6) Based on time delay of 5 seconds or less.

ENCLOSURE 2

WATTS BAR NUCLEAR PLANT
UNIT 1 DRAFT APPENDIX A TECHNICAL SPECIFICATIONS

REVISIONS TO TABLE 3.3-4

TABLE 3.3-4 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION TRIP SETPOINTS

FUNCTIONAL UNIT	TRIP SETPOINT	ALLOWABLE VALUES
6. Auxiliary Feedwater (continued)		
g. Auxiliary Feedwater Suction Pressure-Low (Suction Transfer to ERCW)		
1) Supply Valve for Motor-Driven Pump	≥ ~~2.15~~ 1.70 psig	≥ ~~1.65~~ 0.95 psig
2) Supply Valve for Turbine-Driven Pump	≥ ~~13.1~~ 11.1 psig	≥ ~~12.1~~ 10.0 psig
7. Automatic Switchover To Containment Sump		
a. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.
b. RWST Level - Low Coincident With	≥ 130" from tank base	≥ 126" from tank base
Containment Sump Level - High	≤ 30" above elev. 703'	≤ 32.5" above elev. 703'
And		
Safety Injection	See Item 1. above for all Safety Injection Trip Setpoints/ Allowable Values	
8. 6.9 kV Shutdown Board		
a. Loss of Voltage		
1) Start Diesel Generator		
a) Nominal Voltage Setpoint	4860 volts	4860 ± 97.2 volts
b) Relay Response Time	0.0 volt input to the inverse time relay with a 1.5 second time delay	0.0 volt input to the inverse time relay with a 1.5 ± 1.0 second time delay

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NRC Question

6. ESF Response Times, Table 3.3-5 (page 3/4 3-32)

b. Several response times in the table cannot be verified by information in the Chapter 15 analyses. Please provide additional information so that we can verify the Technical Specification values for the response times for all of the actions listed in the table except for reactor trip and those actions associated with steam generator level low-low and high-high. You need only consider those actions that were assumed to occur in the accident analyses.

Response

The response times listed in Table 3.3-5 have been reviewed. As a result of this review, several revisions to Table 3.3-5 are necessary. (See the attached marked-up technical specifications pages.)

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TABLE 3.3-5

ENGINEERED SAFETY FEATURES RESPONSE TIMES

INITIATING SIGNAL AND FUNCTION	RESPONSE TIME IN SECONDS
1. Manual Initiation	
a. Safety Injection (ECCS)	N.A.
b. Containment Spray	N.A.
c. Phase "A" Isolation	N.A.
d. Phase "B" Isolation	N.A.
e. Ventilation Isolation	N.A.
f. Steam Line Isolation	N.A.
g. Feedwater Isolation	N.A.
h. Auxiliary Feedwater	N.A.
i. Essential Raw Cooling Water	N.A.
j. Control Room Isolation	N.A.
k. Containment Air Return Fan	N.A.
l. Component Cooling Water	N.A.
m. Start Diesel Generators	N.A.
n. Reactor Trip	N.A.
2. Containment Pressure-High	
a. Safety Injection (ECCS)	$\leq 27^{(1)}/12^{(5)}$
1) Reactor Trip	≤ 2
2) Feedwater Isolation	$\leq 8^{(3)}$
3) Containment Isolation-Phase "A"(6)	$\leq 18^{(2)}/28^{(1)}$
4) Containment Ventilation Isolation	~~N.A.~~ $\leq 5.5^{(2)}$
5) Auxiliary Feedwater Pumps	$\leq 60^{(10)}$
6) Essential Raw Cooling Water	$\leq 55^{(2)}/75^{(1)}$
7) Control Room Isolation	N.A.
8) Component Cooling Water	$\leq 43^{(2)}/45^{(1)}$
9) Start Diesel Generators	~~≤ 10~~ ≤ 12
3. Pressurizer Pressure-Low	
a. Safety Injection (ECCS)	$\leq 27^{(1)}/12^{(5)}$
1) Reactor Trip	≤ 2
2) Feedwater Isolation	$\leq 8^{(3)}$
3) Containment Isolation-Phase "A"(6)	$\leq 18^{(2)}/28^{(1)}$
4) Containment Ventilation Isolation	~~N.A.~~ $\leq 5.5^{(2)}$

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TABLE 3.3-5 (Continued)

ENGINEERED SAFETY FEATURES RESPONSE TIMES

INITIATING SIGNAL AND FUNCTION	RESPONSE TIME IN SECONDS
3. Pressurizer Pressure-Low (Continued)	
5) Auxiliary Feedwater Pumps	$\leq 60^{(10)}$
6) Essential Raw Cooling Water	$\leq 65^{(2)}/75^{(1)}$
7) Control Room Isolation	N.A.
8) Component Cooling Water	~~$\leq 43^{(2)}/45^{(1)}$~~
9) Start Diesel Generators	~~≤ 10~~ ≤ 12
4. Differential Pressure Between Steam Lines-High	
a. Safety Injection (ECCS)	$\leq 22^{(4)}/12^{(5)}$
1) Reactor Trip	≤ 2
2) Feedwater Isolation	$\leq 8^{(3)}$
3) Containment Isolation-Phase "A"(5)	$\leq 18^{(2)}/28^{(1)}$
4) Containment Ventilation Isolation	N.A.
5) Auxiliary Feedwater Pumps	$\leq 60^{(10)}$
6) Essential Raw Cooling Water	$\leq 65^{(2)}/75^{(1)}$
7) Control Room Isolation	N.A.
8) Component Cooling Water	~~$\leq 43^{(2)}/45^{(1)}$~~
9) Start Diesel Generators	~~≤ 10~~ ≤ 12
5. Steam Flow in Two Steam Lines - High Coincident with T_{avg}--Low-Low	
a. Safety Injection (ECCS)	$\leq 24^{(4)}/14^{(5)}$
1) Reactor Trip (from SI)	≤ 4
2) Feedwater Isolation	$\leq 10^{(3)}$
3) Containment Isolation-Phase "A"(6)	$\leq 20^{(2)}/30^{(1)}$
4) Containment Ventilation Isolation	N.A.
5) Auxiliary Feedwater Pumps	$\leq 60^{(10)}$
6) Essential Raw Cooling Water	$\leq 67^{(2)}/77^{(1)}$
7) Control Room Isolation	N.A.
8) Component Cooling Water	~~$\leq 43^{(2)}/45^{(1)}$~~
9) Start Diesel Generators	~~≤ 10~~ ≤ 15
b. Steam Line Isolation	≤ 7

3/4 3-32,
3/4 3-33, and
3/4 3-34

The analog channel response time was not included in the diesel start response time for items 2.a.9, 3.a.9, 4.a.9, 5.a.9, and 6.a.9. An additional two seconds was added to these response times for channels not involving temperature measurements. Four seconds were added to the response time for temperature measurements.

TVA questions whether diesel start response time should be listed separately in Table 3.3-5. Diesel generator response time is already addressed in the table by table notations (1), (2), (4), and (5). In addition, diesel generator start times are measured by surveillance requirements 4.8.1.1.2.a.4, 4.8.1.1.2.f.4.b, 4.8.1.1.2.f.5, 4.8.1.1.2.f.6.b, 4.8.1.1.2.f.7, 4.8.1.1.2.g, and 4.8.1.2. We recommend that this item be deleted from the table.

The timers for the containment spray pumps have been changed to improve diesel generator loading. The revised response time is 147 seconds including diesel generator response time.

TABLE 3.3-5 (Continued)

ENGINEERED SAFETY FEATURES RESPONSE TIMES

INITIATING SIGNAL AND FUNCTION	RESPONSE TIME IN SECONDS
3. Pressurizer Pressure-Low (Continued)	
5) Auxiliary Feedwater Pumps	$\leq 60^{(10)}$
6) Essential Raw Cooling Water	$\leq 65^{(2)}/75^{(1)}$
7) Control Room Isolation	N.A.
8) Component Cooling Water	$\leq 43^{(2)}/45^{(1)}$
9) Start Diesel Generators	≤ ~~10~~ 12 - OR DELETE
4. Differential Pressure Between Steam Lines-High	
a. Safety Injection (ECCS)	$\leq 22^{(4)}/12^{(5)}$
1) Reactor Trip	≤ 2
2) Feedwater Isolation	$\leq 8^{(3)}$
3) Containment Isolation-Phase "A"$^{(6)}$	$\leq 18^{(2)}/28^{(1)}$
4) Containment Ventilation Isolation	N.A.
5) Auxiliary Feedwater Pumps	$\leq 60^{(10)}$
6) Essential Raw Cooling Water	$\leq 65^{(2)}/75^{(1)}$
7) Control Room Isolation	N.A.
8) Component Cooling Water	$\leq 43^{(2)}/45^{(1)}$
9) Start Diesel Generators	≤ ~~10~~ 12 - OR DELETE
5. Steam Flow in Two Steam Lines - High Coincident with T_{avg}--Low-Low	
a. Safety Injection (ECCS)	$\leq 24^{(4)}/14^{(5)}$
1) Reactor Trip (from SI)	≤ 4
2) Feedwater Isolation	$\leq 10^{(3)}$
3) Containment Isolation-Phase "A"$^{(6)}$	$\leq 20^{(2)}/30^{(1)}$
4) Containment Ventilation Isolation	N.A.
5) Auxiliary Feedwater Pumps	$\leq 60^{(10)}$
6) Essential Raw Cooling Water	$\leq 67^{(2)}/77^{(1)}$
7) Control Room Isolation	N.A.
8) Component Cooling Water	$\leq 43^{(2)}/45^{(1)}$
9) Start Diesel Generators	≤ ~~10~~ 14 - OR DELETE
b. Steam Line Isolation	≤ 7

TABLE 3.3-5 (Continued)

ENGINEERED SAFETY FEATURES RESPONSE TIMES

INITIATING SIGNAL AND FUNCTION	RESPONSE TIME IN SECONDS
6. Steam Flow in Two Steam Lines-High Coincident with Steam Line Pressure-Low	
a. Safety Injection (ECCS)	≤ 12(5)/22(4)
1) Reactor Trip	≤ 2
2) Feedwater Isolation	≤ 8(3)
3) Containment Isolation-Phase "A"(6)	≤ 18(2)/28(1)
4) Containment Ventilation Isolation	N.A.
5) Auxiliary Feedwater Pumps	≤ 60(10)
6) Essential Raw Cooling Water	≤ 65(2)/75(1)
7) Control Room Isolation	N.A.
8) Component Cooling Water	≤ 43(2)/45(1)
9) Start Diesel Generators	≤ ~~20~~ 12 - OR DELETE
b. Steam Line Isolation	≤ 7
7. Containment Pressure--High-High	
a. Containment Spray	≤ ~~53(2)~~ 147(1)
b. Containment Isolation-Phase "B"	≤ 65(2)/75(1)
c. Steam Line Isolation	≤ 7
d. Containment Air Return Fans	≤ 660
8. Steam Generator Water Level--High-High	
a. Turbine Trip	≤ 2.5
b. Feedwater Isolation	≤ 11(3)
9. Steam Generator Water Level - Low-Low	
a. Motor-driven Auxiliary Feedwater Pumps	≤ 60(7)(1)
b. Turbine-driven Auxiliary Feedwater Pumps	≤ 60(8)
10. RWST Level-Low Coincident with Containment Sump Level-High and Safety Injection	
Automatic Switchover to Containment Sump	≤ 250
11. Loss-of-Offsite Power	
Auxiliary Feedwater Pumps	≤ 60(10)
12. Trip of All Main Feedwater Pumps	
Auxiliary Feedwater Pumps	≤ 60(10)

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Table 3.5-5 - Engineered Safety Features Rsponse Times

The response times for the phase B isolation valves and certain phase A isolation valves have been increased. See change to Table 3.6-2. Table 3.5-5 has been updated to reflect these changes.

TABLE 3.3-5 (Continued)

ENGINEERED SAFETY FEATURES RESPONSE TIMES

INITIATING SIGNAL AND FUNCTION	RESPONSE TIME IN SECONDS
6. Steam Flow in Two Steam Lines-High Coincident with Steam Line Pressure-Low	
a. Safety Injection (ECCS)	$\leq 12^{(5)}/22^{(4)}$
1) Reactor Trip	≤ 2
2) Feedwater Isolation	$\leq 8^{(3)}$
3) Containment Isolation-Phase "A"$^{(6)}$	$\leq 18^{(2)}/28^{(1)}$
4) Containment Ventilation Isolation	N.A.
5) Auxiliary Feedwater Pumps	$\leq 60^{(10)}$
6) Essential Raw Cooling Water	$\leq 65^{(2)}/75^{(1)}$
7) Control Room Isolation	N.A.
8) Component Cooling Water	$\leq 43^{(2)}/45^{(1)}$
9) Start Diesel Generators	≤ 10
b. Steam Line Isolation	≤ 7
7. Containment Pressure--High-High	
a. Containment Spray	$\leq 58^{(2)}$
b. Containment Isolation-Phase "B"	$\leq \cancel{65}^{(2)}/\cancel{75}^{(1)}$ 71 81
c. Steam Line Isolation	≤ 7
d. Containment Air Return Fans	≤ 660
8. Steam Generator Water Level--High-High	
a. Turbine Trip	≤ 2.5
b. Feedwater Isolation	$\leq 11^{(3)}$
9. Steam Generator Water Level - Low-Low	
a. Motor-driven Auxiliary Feedwater Pumps	$\leq 60^{(7)(1)}$
b. Turbine-driven Auxiliary Feedwater Pumps	$\leq 60^{(8)}$
10. RWST Level-Low Coincident with Containment Sump Level-High and Safety Injection	
Automatic Switchover to Containment Sump	≤ 250
11. Loss-of-Offsite Power	
Auxiliary Feedwater Pumps	$\leq 60^{(10)}$
12. Trip of All Main Feedwater Pumps	
Auxiliary Feedwater Pumps	$\leq 60^{(10)}$

3/4 3-36	Typographical errors in table notation six have been corrected. The note was not changed when NRC changed the format for the table itself.

TABLE 3.3-5 (Continued)

TABLE NOTATIONS

(1) Diesel generator starting and sequence loading delays included.

(2) Diesel generator starting and sequence loading delay not included. Offsite power available.

(3) Air operated valves.

(4) Diesel generator starting and sequence loading delay included. RHR & SI pumps not included.

(5) Diesel generator starting and sequence loading delays not included. SI and RHR pumps not included.

(6) The following valves are exceptions to the response time shown in the table and will have the following response times for the initiating signals and functions:

	FCV-70-143	FCV-62-77 and FCV-26-240, -243	FCV-61-96, -97, -110, -122, -191, -192, -193, -194
2.a.3	~~2.d~~ 68 ~~62~~(2)/~~72~~(1) 78	~~2.d~~ 22(2)/32(1)	~~2.d~~ 32
3.a.3	~~3.d~~ 68 ~~62~~(2)/~~72~~(1) 78	~~3.d~~ 22(2)/32(1)	~~3.d~~ 32
4.a.3	~~4.d~~ 68 ~~62~~(2)/~~72~~(1) 78	~~4.d~~ 22(2)/32(1)	~~4.d~~ 32
5.a.3	~~5.d~~ 70 ~~64~~(2)/~~74~~(1) 80	~~5.d~~ 24(2)/34(1)	~~5.d~~ 34
6.a.3	~~6.d~~ 68 ~~62~~(2)/~~72~~(1) 78	~~6.d~~ 22(2)/32(1)	~~6.d~~ 32

(7) On 2/3 any steam generator.

(8) On 2/3 in 2/4 steam generators.

(9) The response time is measured from the time the 6.9 kV shutdown boards voltage exceeds the Setpoint until the time full voltage is returned for the loss of voltage sensors; or from the time the degraded voltage timers generate a signal to start the diesels or shed loads until the time full voltage is returned for the degraded voltage sensors.

(10) For motor-driven pumps only, the diesel generator starting and sequence loading delays are included.

WATTS BAR NUCLEAR PLANT
EXEMPTION REQUEST

TECHNICAL SPECIFICATION 4.3.2.1 TABLE 4.3-2
ESFAS SLAVE RELAY TESTING REQUIREMENTS

SLAVE RELAY TESTING
Table 4.3-2
Justification For Exemption

By letter dated June 19, 1984, we requested relaxation from testing at power ten (10) ESFAS slave relays. Currently, our Technical Specifications require that ESFAS relays be tested on a quarterly basis. The following is additional discussion/justification for the requested relaxation.

Attached are TVA logic diagrams 47W611-99 sheets 3 and 4 which identify all the ESFAS slave relays. The equipment actuated by the slave relays are identified in the right hand column of each table. The eight (8) relays we are now requesting relief on are circled on the prints.

Each slave relay we are requesting relief on is discussed below:

K603A, K603B

REASON FOR NOT TESTING AT POWER:

These relays close LCV-62-132 and 133. The closure of these valves cause loss of suction to the charging pumps. This requires opening of alternate suction lines to the RWST which would introduce 2,000 ppm of boron into the Reactor Coolant System causing unstable unit operation. These valves isolate the Volume Control Tank from the CCP suction on a SI signal. They are series isolation valves which get their closure signal and power supply from different trains. Either one of the two slave relays functioning to close one of the valves will achieve the safety function required. Furthermore, failure of one relay will in no way affect the operation of the other relay. These valves can still be manually closed from the MCR.

OTHER DEVICES ACTUATED BY THESE RELAYS:

FCV's 62-90 and 91 are charging flow isolation valves. These train seperated series isolation valves close on an SI signal to force injection flow through the cold leg injection lines. Again, either one of these valves closing will fulfill the required safety function. Also they can still be closed manually from the MCR. It should be noted that closing of these valves during power operation will cause an unnecessary thermal cycle on the regenerative heat exchanger. FCV's 63-25 and 26 are BIT outlet parallel isolation valves. Since these are parallel isolation valves, either one opening on an SI signal will achieve the required safety function. A failure of one slave relay will not affect the signal to the other valve. FCV's 63-41 and 42 are BIT to BAT recirculation isolation valves. Because of the deletion of the BIT 20,000 ppm requirement from the design basis of our plant these valves no longer perform safety functions and thus need not be tested. Because of the deletion of the 20,000 ppm requirement for the BIT from the design basis of our plant, BIT heaters 1A-A and 1B-B are no longer required to function and thus need not be tested. FCV's 63-98 and 118 are SIS cold leg accumulator 1 and 2 isolation valves. These valves are required by Specification 3.5.1.1 to be opened with power removed above 1,000 psig and thus can not be tested. FCV's 74-16 and 28 are the RHR heat exchanger outlet flow control valves. These valves, although administratively required to be fully open above mode 4, receive a signal to open fully upon a safety injection signal. If the administrative requirments were bypassed and a failure of the slave relay caused one of these valves to not fully open the other train of RHR is sized to completely fulfill the required safety function. Also the operator could still open these valves from the MCR.

K604A, K604B

REASON FOR NOT TESTING AT POWER:

These relays open FCV 62-135, and 62-136, which are charging pump suction isolation valves from the RWST. Opening of these valves while at power would introduce 2,000 ppm boron into the RCS causing unstable unit operation. These valves are parellel valves which get their open signal and power supply from seperate trains. Either valve opening will achieve the required safety function. Failure of one relay will not affect the operation of the other valve. Additionally, these valves can still be opened from the main control room.

Also, these relays deenergize the PRZ heaters, (both control and backup groups). At power the deenergizing of these heaters would limit our normal RCS pressure control capabilities, and could result in unnecessary RCS pressure transients. The failure of these heaters to deenergize on the SI signal would not adversly affect the plant. They are deenergized only to protect the heaters from burning out on level loss in the PRZ. Again, these heaters can be deenergized from the MCR if the relays were to fail.

OTHER DEVICES ACTUATED BY THESE RELAYS:

These relays also open FCV-63-39 and 63-40 which are the inlet parallel isolation valves to the BIT. Since these are parallel isolation valves, either one opening on an SI signal will achieve the required function. A failure of one slave relay will not affect the signal to the other valve. Additionally, these valves could still be opened via the MCR handswitches.

FCV-63-38 is the BAT to BIT recirculation isolation valve. Because of the deletion of the 20,000 ppm requirement for the BIT from the design basis of the plant this valve no longer performs a safety function and thus need not be tested.

K609A, K609B

REASON FOR NOT TESTING EVERY 92 DAYS:

Actuating either of these relays will result in all four diesel generators starting. This will result in 32 unnecessary D/G starts per year (16 per relay). As discussed in NRC Generic Letter 84-15, additional cold starts may result in excessive mechanical wear and reduced D/G reliability. As stated above, either of the relays will start all four D/G's, thus a failure of one relay will not prevent the diesels from starting on an SI signal. Additionally, the failure of both relays would not prevent the diesels from starting on a low voltage signal from the shutdown boards (which is the only time they are actually required to perform their safety function) or a manual start signal from the MCR. TVA proposes to test these slave relays only once every 18 months to coincide with S.R. 4.8.1.1.2.f.6, "Simulating a loss-of-offsite power in conjunction with an ESF actuation test signal." This will appropriately cut down on the number of unnecessary D/G starts.

OTHER DEVICES ACTUATED BY THESE RELAYS:

FCV 63-80 and 63-67 are the cold leg accumulators isolation valves. These valves are required by LCO 3.5.1.1 to be open with power removed whenever the RCS pressure is greater than 1,000 psig and thus can not be tested at power. These relays also stop the two reactor building floor and equipment drain pumps. This is for pump protection only since the path out of containment isolates on a phase A containment isolation signal (which will come from an SI signal). Thus the failure of these relays to stop these pumps on an SI signal will not affect the safe operation of the plant. FCV 87-23 and 87-24 are the UHI isolation valve gags. These gags close upon an SI signal coincident with the isolation valve being fully closed. Thus, the failure of these relays to close the gag will not defeat the injection of the UHI into the RCS or the subsequent isolation of the UHI lines to prevent nitrogen being introduced into the RCS. The gags serve only as an added provision to help prevent the valves from drifting back open (Note: the isolation valves are series valves designed not to reopen, i.e., 2 valves would have to drift back open before any nitrogen could potentially be introduced into the RCS). Finally, these relays also actuate an additional delay timer for the CCS thermal barrier booster pumps and the high pressure fire protection pumps. The only time these relays have any effect is when there is a blackout while (coincident with) an SI signal is present. Under these conditions it delays the pump start an additional .5 to 3 seconds to accommodate D/G loading. The failure of these relays will in no way inhibit the start signal to these pumps. The additional load to the D/G from these small thermal barrier booster pumps starting 3 seconds early (due to failure of relay), would be tolerable. In order for the relays to be required to initiate the additional .5 second delay in the HPFP start circuit there must be a pump start signal coincident with an SI and blackout. This coincidence, however, is not in the design basis of the plant and thus need not be considered.

As can be seen, the testing of these two relays on an 18 month interval will not adversly affect the safe operation of the plant, but will actually increase the reliability of the D/G's.

K625A, K625B

REASON FOR NOT TESTING AT POWER:

These relays actuate the containment air return fans. Starting these fans during normal operation would cause the lower inlet doors of the ice condenser to open and force air thorugh the ice bed. This could result in ice melting which is not accounted for in minimum ice weight analysis. Each fan is sized for 100% capacity, so the failure of one relay will not affect the capability of the other fan to perform the required function. Additionally, the failure of these relays doesn't defeat the manual start capability via the main control room handswitches.

OTHER DEVICES ACTUATED BY THESE RELAYS:

FCV's - 67-83, 87, 91, 95, 99, 103, 107, 111, 130, 133, 138, 141, 295, 296, 297, and 298 are containment isolation valves for ERCW to the upper and lower compartment coolers, RCP motor coolers, and CRDM coolers which all get a phase B closure signal. Each of these valves has either a redundant (series) isolation valve actuated by slave relays that are not being exempted or a check valve in series which would isolate the pathway out of containment (see attached TVA dwg. 47W 845-3). Thus the failure of these relays to close the isolation valves would not prevent the safety function from being performed. Additionally, the relay failures would not affect the closure of these valves via the MCR handswitches. These relays also supply a stop signal to the above cooler unit fans. However, this is for fan protection only. Thus, failure of these relays to stop the fans would not adversely affect the safe operation of the plant.

As can be seen on the attached logic prints the equipment assignment to each slave relay has resulted in a small fraction of the total devices actuated not being able to be tested at power. This could be minimized further by design changes, but TVA has decided this would not be practical.

SUMMARY

The above discussion of each slave relay that we are requesting relief on has shown that the testing of these relays could result in unsafe or unstable plant operations. Additionally, we have shown that each device that will not be tested at power has 1) sufficient redundancy or backups so that a failure of that slave relay to actuate the particular device could be tolerated without defeating the required safety function; or 2) the equipment failing has no consequence on the safe operation of the plant.

ENCLOSURE 2

WATTS BAR NUCLEAR PLANT

PROPOSED CHANGES TO THE UNIT 1 TECHNICAL SPECIFICATIONS
ESFAS SLAVE RELAY TESTING REQUIREMENTS

TABLE 4.3-2

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	ANALOG CHANNEL OPERATIONAL TEST	TRIP ACTUATING DEVICE OPERATIONAL TEST	ACTUATION LOGIC TEST	MASTER RELAY TEST	SLAVE RELAY TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
1. Safety Injection (Reactor Trip, Turbine Trip, Feedwater, Isolation, Control Room Isolation, Start Diesel Generators, Component Cooling Water, and Essential Raw Cooling Water)								
a. Manual Initiation	N.A.	N.A.	N.A.	R	N.A.	N.A.	N.A.	1, 2, 3, 4
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.	N.A.	N.A.	M(1)	M(1)	Q(4)	1, 2, 3, 4
c. Containment Pressure-High	S	R	M	N.A.	N.A.	N.A.	N.A.	1, 2, 3
d. Pressurizer Pressure-Low	S	R	M	N.A.	N.A.	N.A.	N.A.	1, 2, 3
e. Differential Pressure Between Steam Lines--High	S	R	M	N.A.	N.A.	N.A.	N.A.	1, 2, 3
f. Steam Flow in Two Steam Lines--High Coincident With	S	R	M	N.A.	N.A.	N.A.	N.A.	1, 2, 3
Either 1) T_{avg}--Low-Low	S	R	M	N.A.	N.A.	N.A.	N.A.	1, 2, 3
Or 2) Steam Line Pressure--Low	S	R	M	N.A.	N.A.	N.A.	N.A.	1, 2, 3
2. Containment Spray								
a. Manual Initiation	N.A.	N.A.	N.A.	R	N.A.	N.A.	N.A.	1, 2, 3, 4
b. Automatic Actuation Logic and Actuation Relays	N.A.	N.A.	N.A.	N.A.	M(1)	M(1)	Q	1, 2, 3, 4
c. Containment Pressure--High-High	S	R	M	N.A.	N.A.	N.A.	N.A.	1, 2, 3

TABLE 4.3-2 (Continued)

ENGINEERED SAFETY FEATURES ACTUATION SYSTEM INSTRUMENTATION SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	ANALOG CHANNEL OPERATIONAL TEST	TRIP ACTUATING DEVICE OPERATIONAL TEST	ACTUATION LOGIC TEST	MASTER RELAY TEST	SLAVE RELAY TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
3. Containment Isolation								
a. Phase "A" Isolation								
1) Manual Initiation	N.A.	N.A.	N.A.	R	N.A.	N.A.	N.A.	1, 2, 3, 4
2) Automatic Actuation Logic and Actuation Relays	N.A	N.A.	N.A.	N.A.	M(1)	M(1)	Q	1, 2, 3, 4
3) Safety Injection	See Item 1. above for all Safety Injection Surveillance Requirements.							
b. Phase "B" Isolation								
1) Manual Initiation	N.A.	N.A.	N.A.	R	N.A.	N.A.	N.A.	1, 2, 3, 4
2) Automatic Actuation Logic and Actuation Relays	N.A.	N.A.	N.A.	N.A.	M(1)	M(1)	Q (4)	1, 2, 3, 4
3) Containment Pressure-High-High	S	R	M	N.A.	N.A.	N.A.	N.A.	1, 2, 3
c. Containment Ventilation Isolation								
1) Manual Initiation	N.A.	N.A.	N.A.	R	N.A.	N.A.	N.A.	1, 2, 3, 4
2) Automatic Actuation Logic and Actuation Relays	N.A.	N.A.	N.A.	N.A.	M(1)	M(1)	Q	1, 2, 3, 4
3) Safety Injection	See Item 1. above for all Safety Injection Surveillance Requirements.							

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TABLE 4.3-2 (Continued)

TABLE NOTATION

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

(2) Monthly testing shall consist of relay testing excluding final actuation of the pumps or valves.

(3) Monthly testing shall consist of voltage sensor relay testing excluding actuation of the load shedding, diesel start, and time delay timers.

(4) Slave relays K603A, K603B, K604A, K604B (SI) and K625A, K625B (phase B) shall be tested during each COLD SHUTDOWN exceeding 24 hours unless tested during the previous 6 months. Testing of FCV-63-67, -80, -98, and -118 is not required. K609A, K609B (SI) shall be tested every 18 months.

Pages 3/43-44, 3/43-45, and 3/43-46

By letter dated September 5, 1979 (A27 790918 006), NRC granted an exemption to 10 CFR Part 70.24 when they issued the special muclear material license for Watts Bar. The method of storing or handling muclear fuel assemblies will not change once an operating license is granted. The exemption to 10 CFK Part 70.24 should be specifically incorporated into the operating license. The requirements for a criticality monitor should be deleted from technical specification 3.3.3.1.

The correct terminology at Watts Bar is auxiliary building instead of fuel building.

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TABLE 3.3-6

RADIATION MONITORING INSTRUMENTATION FOR PLANT OPERATIONS

FUNCTIONAL UNIT	CHANNELS TO TRIP/ALARM	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ALARM/TRIP SETPOINT	ACTION
1. ~~Fuel~~ AUXILIARY Building Isolation					
Radiation Level-High ~~and Criticality~~ (RE-90-102 and RE-90-103)	1	2	*	$\leq$ 15 mR/h	28
2. Containment Atmosphere					
a. Gaseous Radioactivity-RCS Leakage Detection	N.A.	1	1, 2, 3, 4	N.A.	29
b. Particulate Radioactivity RCS Leakage Detection	N.A.	1	1, 2, 3, 4	N.A.	29
3. Control Room Ventilation Isolation					
Control Room Air Intake Radioactivity-High (RE-90-125 and RE-90-126)	1	2	All	400 cpm**	27

Previous Change Here

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TABLE 3.3-6 (Continued)

TABLE NOTATIONS

*With irradiated fuel in the fuel storage areas.

**400 cpm is equivalent to 1 x 10-5 ~~m~~μCi/cm3 of Xe-133.

ACTION STATEMENTS

ACTION 27 - With the number of OPERABLE channels one less than the Minimum Channels OPERABLE requirement, within 1 hour isolate the Control Room Ventilation System and initiate operation of the Control Room Ventilation System in the recirculation mode.

ACTION 28 - With the number of OPERABLE channels one less than the Minimum Channels OPERABLE requirement, ACTION a. of Specification 3.9.12 must be satisfied. With both channels inoperable, provid an appropriate portable continuous monitor with the same Alarm Setpoint in the fuel pool area and satisfy ACTION b. of Specification 3.9.12 with one Auxiliary Building Gas Treatment System train in operation.

ACTION 29 - Must satisfy the ACTION requirement for Specification 3.4.6.1. Previous Change Here

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TABLE 4.3-3

RADIATION MONITORING INSTRUMENTATION FOR PLANT OPERATIONS SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	ANALOG CHANNEL OPERATIONAL TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
1. ~~Fuel~~ AUXILIARY Building Isolation				
Radiation Level-High ~~and Criticality~~ (RE-90-102 and RE-90-103)	S	R	M	*
2. Containment Atmosphere				
a. Gaseous Radioactivity-RCS Leakage Detection	S	R	M	1, 2, 3, 4
b. Particulate Radioactivity - RCS Leakage Detection	S	R	M	1, 2, 3, 4
3. Control Room Ventilation Isolation				
Control Room Air Intake Radioactivity-High (RE-90-125 and RE-90-126)	S	R	M	All

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* - With Irradiated fuel in the fuel storage areas.

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3/4 3-44, 3/4 3-45, 3/4 3-46, 3/4 3-47, 3/4 4-18, B 3/4 3-2 and B 3/4 4-4

Tables 3.3-6 and 4.3-3 should be revised as indicated to improve clarity and elminate redundancy.

The fuel storage pool area has two fully redundant monitors which perform both radiation and criticality detection; therefore, listing separate requirements and setpoints for the same monitor is confusing and should be deleted from Tables 3.3-6 and 4.3-3.

The containment atmosphere monitor requirements should be deleted from Tables 3.3-6 and 4.3-3 since they are redundnat to technical specification 3.4.6.1. The minimum channels operable, applicable modes, and ACTION requirements are identical; however, the surveillance frequencies should be included in Surveillance Requirement 4.4.6.1 as indicated.

ACTION statement 28 for Table 3.3-6 should be revised as indicated to identify the correlation between the subject monitors and the Auxiliary Building Gas Treatment System.

Bases 3/4.3.3.1 and 3/4.4.6.1 should be revised as indicated for clarification purposes.

TABLE 3.3-6

RADIATION MONITORING INSTRUMENTATION FOR PLANT OPERATIONS

FUNCTIONAL UNIT	CHANNELS TO TRIP/ALARM	MINIMUM CHANNELS OPERABLE	APPLICABLE MODES	ALARM/TRIP SETPOINT	ACTION
1. ~~Fuel~~ Auxiliary Building Isolation					
Radiation Level-High and Criticality (RE-90-102 and RE-90-103)	1	2	*	$\leq$ 15 mR/h	28
~~2. Containment Atmosphere~~					
~~a. Gaseous Radioactivity-RCS Leakage Detection~~	~~N.A.~~	~~1~~	~~1, 2, 3, 4~~	~~N.A.~~	~~29~~
~~b. Particulate Radioactivity RCS Leakage Detection~~	~~N.A.~~	~~1~~	~~1, 2, 3, 4~~	~~N.A.~~	~~29~~
2 ~~3.~~ Control Room Ventilation Isolation					
Control Room Air Intake Radioactivity-High (RE-90-125 and RE-90-126)	1	2	All	400 cpm**	27

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TABLE 3.3-6 (Continued)

TABLE NOTATIONS

*With fuel in the fuel storage areas.

**400 cpm is equivalent to 1 x 10-5 ~~mCi~~ uCi/cm3 of Xe-133.

ACTION STATEMENTS

ACTION 27 - With the number of OPERABLE channels one less than the Minimum Channels OPERABLE requirement, within 1 hour isolate the Control Room Ventilation System and initiate operation of the Control Room Ventilation System in the recirculation mode.

ACTION 28 - With the number of OPERABLE channels one less than the Minimum Channels OPERABLE requirement, ACTION a. of Specification 3.9.12 must be satisfied. With both channels inoperable, provid an appropriate portable continuous monitor with the same Alarm Setpoint in the fuel pool area and satisfy ACTION b. of Specification 3.9.12 ~~with one Auxiliary Building Gas Treatment System train in operati~~on.

~~ACTION 29 - Must satisfy the ACTION requirement for Specification 3.4.6.1~~.

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TABLE 4.3-3

RADIATION MONITORING INSTRUMENTATION FOR PLANT OPERATIONS SURVEILLANCE REQUIREMENTS

FUNCTIONAL UNIT	CHANNEL CHECK	CHANNEL CALIBRATION	ANALOG CHANNEL OPERATIONAL TEST	MODES FOR WHICH SURVEILLANCE IS REQUIRED
1. ~~Fuel~~ Auxiliary Building Isolation				
Radiation Level-High and Criticality (RE-90-102 and RE-90-103)	S	R	M	*
~~2. Containment Atmosphere~~				
~~a. Gaseous Radioactivity-RCS Leakage Detection~~	~~S~~	~~R~~	~~M~~	~~1, 2, 3, 4~~
~~b. Particulate Radioactivity - RCS Leakage Detection~~	~~S~~	~~R~~	~~M~~	~~1, 2, 3, 4~~
2 ~~3~~. Control Room Ventilation Isolation				
Control Room Air Intake Radioactivity-High (RE-90-125 and RE-90-126)	S	R	M	All

* - With fuel in the fuel storage areas.

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REACTOR COOLANT SYSTEM

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3/4.4.6 REACTOR COOLANT SYSTEM LEAKAGE

LEAKAGE DETECTION SYSTEMS

LIMITING CONDITION FOR OPERATION

3.4.6.1 The following Reactor Coolant System Leakage Detection Systems shall be OPERABLE:

a. The Lower Containment Atmosphere Gaseous Radioactivity Monitoring System,

b. The Containment Pocket Sump Level Monitoring System, and

c. The Lower Containment Atmosphere Particulate Radioactivity Monitoring System.

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

ACTION:

With only two of the above required Leakage Detection Systems OPERABLE, operation may continue for up to 30 days provided grab samples of the containment atmosphere are obtained and analyzed for gaseous and particulate radioactivity at least once per 24 hours when the required Gaseous or Particulate Radioactivity Monitoring System is inoperable; otherwise, be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.4.6.1 The Leakage Detection Systems shall be demonstrated OPERABLE by:

a. Lower Containment Atmosphere Gaseous And ~~Particulate Monitoring System~~-performance of CHANNEL CHECK, CHANNEL CALIBRATION and ANALOG CHANNEL OPERATIONAL TEST ~~at the frequencies specified in Table 4.3-3, and~~

b. Containment Pocket Sump Level Monitoring System-performance of CHANNEL CALIBRATION at least once per 18 months.

at least once per 12 hours, once every 31 days and once every 18 months, respectively, and

3/4 3-45	Action 28 should be revised to be consistent with TVA's previous request. With both monitors inoperable, action is taken to prohibit operation that would result in a fuel handling accident in accordance with action b to specification 3.9.12. Further remedial action to start and run one train of the auxiliary building gas treatment system provides no additional safety benefit. TVA considers such a measure as punitive rather than remedial.

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TABLE 3.3-6 (Continued)

TABLE NOTATIONS

*With fuel in the fuel storage areas.

**400 cpm is equivalent to 1 x 10-5 mCi/cm3 of Xe-133.

ACTION STATEMENTS

ACTION 27 - With the number of OPERABLE channels one less than the Minimum Channels OPERABLE requirement, within 1 hour isolate the Control Room Ventilation System and initiate operation of the Control Room Ventilation System in the recirculation mode.

ACTION 28 - With the number of OPERABLE channels one less than the Minimum Channels OPERABLE requirement, ACTION a. of Specification 3.9.12 must be satisfied. With both channels inoperable, provid an appropriate portable continuous monitor with the same Alarm Setpoint in the fuel pool area and satisfy ACTION b. of Specification 3.9.12. ~~with one Auxiliary Building Gas Treatment System train in operation~~.

ACTION 29 - Must satisfy the ACTION requirement for Specification 3.4.6.1.

Tables 3.3-7 and 4.3-4 Seismic Monitors

These tables have been revised to include identification of additional monitors that provide control room indication.

TABLE 3.3-7

SEISMIC MONITORING INSTRUMENTATION

INSTRUMENTS AND SENSOR LOCATIONS	MEASUREMENT RANGE	MINIMUM INSTRUMENTS OPERABLE
1. Triaxial Time-History Accelerographs		
a. 0-XT-52-75A Annulus El. 703	0 - 1.0g	1*
b. 0-XT-52-75B Cont. El. 757	0 - 1.0g	1*
c. 0-XT-52-75D D/G Bldg. El. 742	0 - 1.0g	1*
2. Triaxial Peak Accelerographs		
a. 0-XR-52-76A Cont. El. 725	0 - 5.0 g	1
b. 0-XR-52-76B Cont. El. 730	0 - 5.0 g	1
c. 0-XR-52-76D Control Bldg. El. 755	0 - 5.0 g	1
3. Triaxial Seismic Switches		
0-XS-52-80 Annulus El. 703	0.025 - 0.25g	1*
4. Triaxial Response-Spectrum Recorders		
a. 0-XR-52-77A Annulus El. 703	2 - 25.4 Hz	1*
b. 0-XR-52-77B Cont. El. 757	2 - 25.4 Hz	1
c. 0-XR-52-77D Cont. El. 755	2 - 25.4 Hz	1
d. 0-XR-52-77E D/G Bldg. El. 742	2 - 25.4 Hz	1

*With reactor control room indication

TABLE 4.3-4

SEISMIC MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENTS AND SENSOR LOCATIONS	CHANNEL CHECK	CHANNEL CALIBRATION	ANALOG CHANNEL OPERATIONAL TEST
1. Triaxial Time-History Accelerographs			
a. 0-XT-52-75A Annulus El. 703**	M*	R***	SA
b. 0-XT-52-75B Cont. El. 757**	M*	R***	SA
c. 0-XT-52-75D D/G Bldg. El. 742**	M*	R***	SA
2. Triaxial Peak Accelerographs			
a. 0-XR-52-76A Cont. El. 725	N.A.	R	N.A.
b. 0-XR-52-76B Cont. El. 730	N.A.	R	N.A.
c. 0-XR-52-76D Control Bldg. El. 755	N.A.	R	N.A.
3. Triaxial Seismic Switches			
0-XS-52-80 Annulus El. 703**	M	R	SA
4. Triaxial Response-Spectrum Recorders			
a. 0-XR-52-77A Annulus El. 703**	M	R	SA
b. 0-XR-52-77B Cont. El. 757	N.A.	R	N.A.
c. 0-XR-52-77D Cont. El. 755	N.A.	R	N.A.
d. 0-XR-52-77E D/G Bldg. El. 742	N.A.	R	N.A.

*Except seismic trigger.
**With reactor control room indications.
***Includes seismic trigger.

Table 3.3-10 - Accident Monitoring Instrumentation

The identification numbers for the steam line radiation monitors have been added for clarity. The minimum channels operable column has been revised to reflect the fact that one monitor is installed for each steam line.

TABLE 3.3-10 (Continued)

ACCIDENT MONITORING INSTRUMENTATION

INSTRUMENT	TOTAL NO. OF CHANNELS	MINIMUM CHANNELS OPERABLE
18. Shield Building Vent-High Range Noble Gas Monitor (RE-90-401)	N.A.	1
19. Condenser Vacuum Exhaust Vent-High Range Noble Gas Monitor (RE-90-404)	N.A.	1
20. Steam Line Relief-Noble Gas Monitor (RE-90-421, 422, 423, 424)	N.A.	1/steam line
21. Reactor Vessel Water Level	2	1
22. Containment Atmosphere - High Range Monitor (RE-90-271, 272, 273, and 274)	N.A.	1/upper containment & 1/lower containment

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Pages 3/43-59, and 3/43-61

The reactor vessel water level system cannot be used until the new emergency operating procedures governing the use of this system are in place. This is presently scheduled to occur before startup after the first refueling outage for unit 1. The operability and surveillance requirements should not be effective until the reactor vessel water level system can and must be used to mitegate the effects of potential accident sequences. Requiring operability and surveillance prior to the issuance of the new emergency procedures is an economic burden and an economic risk. Plant shutdown should not be required for an inoperable system that cannot be used anyway.

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TABLE 3.3-(Continued)

ACCIDENT MONITORING INSTRUMENTATION

INSTRUMENT	TOTAL NO. OF CHANNELS	MINIMUM CHANNELS OPERABLE
18. Shield Building Vent-High Range Noble Gas Monitor (RE-90-401)	N.A.	1
19. Condenser Vacuum Exhaust Vent-High Range Noble Gas Monitor (RE-90-404)	N.A.	1
20. Steam Line Relief-Noble Gas Monitor	N.A.	1
21. Reactor Vessel Water Level *	2	1
22. Containment Atmosphere - High Range Monitor (RE-90-271, 272, 273, and 274)	N.A.	1/upper containment & 1/lower containment

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* The OPERABILITY requirements for the Reactor Vessel Water Level system are not applicable until the new emergency operating procedures required by NUREG-0737 are in effect.

TABLE 4. (Continued)

ACCIDENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK	CHANNEL CALIBRATION
18. Shield Building Vent-High Range Noble Gas Monitor (RE-90-401)	M	R*
19. Condenser Vacuum Exhaust Vent-High Range Noble Gas Monitor (RE-90-404)	M	R*
20. Steam Line Relief-Noble Gas Monitor	M	R*
21. Reactor Vessel Water Level **	M	R
22. Containment Atmosphere - High Range Monitor (RE-90-271, 272, 273, and 274)	M	R*

*CHANNEL CALIBRATION may consist of an electronic calibration of the channel, not including the detector, for range decades above 10R/h and a one point calibration check of the detector below 10R/h with an installed or portable gamma source.

** The surveillance requirements for the Reactor Vessel Water Level system are not applicable until the new emergency operating procedures required by NUREG-0737 are in effect.

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3/4 3-70	Zones 128 and 129 are being deleted because they do not contain safety-related equipment.

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TABLE 3.3-11 (Continued)

FIRE DETECTION INSTRUMENTATION

ZONE	INSTRUMENT LOCATION	TOTAL NUMBER OF INSTRUMENTS** HEAT (x/y)	FLAME (x/y)	SMOKE (x/y)
C.	Auxiliary Building (Continued)			
98	Cntmt. Purge Air Fltr., A & B, Duct. Det., El. 713			0/2
99	Cntmt. Purge Air Fltr., A & B, Duct. Det., El. 713			0/2
102	Pipe Gallery, El. 713			0/4
103	Pipe Gallery, El. 713			0/4
106	Aux. Bldg. A5-A11, Col. T-W, El. 713			0/8
107	Aux. Bldg. A5-A11, Col. T-W, El. 713			0/8
108	Radio Chemical Lab. Area, El. 713			0/3
109	Radio Chemical Lab. Area, El. 713			0/3
110	Aux. Bldg. A1-A8, Col. Q-U, El. 713			0/18
111	Aux. Bldg. A1-A8, Col. Q-U, El. 713			0/19
112	Aux. Bldg. A8-A15, Col. Q-U, El. 713			0/9
113	Aux. Bldg. A8-A15, Col. Q-U, El. 713			0/9
114	Waste Packaging Area, El. 729			0/3
115	Waste Packaging Area, El. 729			0/3
116	Cask Loading Area, El. 729			0/2
117	Cask Loading Area, El. 729			0/2
118	New Fuel Storage Area			4/0
120	Aux. Bldg. Gas Trtmt. Fltr., El. 737			0/1
121	Aux. Bldg. Gas Trtmt. Fltr., El. 737			0/1
123	Vol. Control Tank Rm. 1A, El. 713			0/1
125	Vol. Control Tank Rm. 1A, El. 713			0/1
~~128~~	~~Post Accident Sampling Rm., El. 729~~			~~0/3~~
~~129~~	~~Post Accident Sampling Rm., El. 729~~			~~0/3~~

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3/4 3-78 & 3/4 3-80	It appears that NRC incorrectly listed the radiation monitor numbers for item 1.b under item 1.a.

WATTS BAR - UNIT 1

TA[illegible] 3.3-12

RADIOACTIVE LIQUID EFFLUENT MONITORING INSTRUMENTATION

INSTRUMENT	MINIMUM CHANNELS OPERABLE	ACTION
1. Radioactivity Monitors Providing alarm and Automatic Termination of Release		
a. Waste Disposal System Liquid Effluent Line (RE-90-122 ~~120 and 121~~)	1	31
b. Steam Generator Blowdown Effluent Line (RE-90-[illegible] 120 and 121)	1	32
c. Condensate Demineralizer Regenerant Effluent Line (RE-90-225)	1	31
2. Radioactivity Monitors Providing Alarm But Not Providing Automatic Termination of Release		
a. Essential Raw Cooling Water Effluent Line (RE-90-133 & 90-140 or RE-90-134 & 90-141)	1	33
b. Turbine Building Sump Effluent Line (RE-90-212)	1	33
c. Plant Liquid Discharge Line (RE-90-211)	1	33
3. Flow Rate Measurement Devices		
a. Waste Disposal System Liquid Radwaste Effluent Line	1	34
b. Condensate Demineralizer Regenerant Effluent Line	1	34
c. Steam Generator Blowdown Effluent Line	1	34
d. Diffuser Discharge Effluent Line	1	34
4. Tank Level Indicating Devices		
a. Condensate Storage Tank	1	35
b. Steam Generator Layup Tank*	1	35

*Required when connected to the Secondary Coolant System.

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TABL[illegible].3-8

RADIOACTIVE LIQUID EFFLUENT MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENT	CHANNEL CHECK	SOURCE CHECK	CHANNEL CALIBRATION	ANALOG CHANNEL OPERATIONAL TEST
1. Radioactivity Monitors Providing Alarm and Automatic Termination of Release				
a. Waste Disposal System Liquid Effluent Line (RE-90-~~120 and 121)~~ 122)	D	P	R(3)	Q(1)
b. Steam Generator Blowdown Effluent Line (RE-90-~~124)~~ 120 and 121)	D	M	R(3)	Q(1)
c. Condensate Demineralizer Regenerant Effluent Line (RE-90-225)	D	M	R(3)	Q(1)
2. Radioactivity Monitors Providing Alarm But Not Providing Automatic Termination of Release				
a. Essential Raw Cooling Water Effluent Line (RE-90-133 & 90-140 or RE-90-134 & 90-141)	D	M	R(3)	Q(2)
b. Turbine Building Sump Effluent Line (RE-90-212)	D	M	R(3)	Q(2)
c. Plant Liquid Discharge Line (RE-90-211)	D	M	R(3)	Q(1)
3. Flow Rate Measurement Devices				
a. Waste Disposal System Liquid Effluent Line	D(4)	N.A.	R	Q
b. Steam Generator Blowdown Effluent Line	D(4)	N.A.	R	Q
c. Condensate Demineralizer Regenerant Effluent Line	D(4)	N.A.	R	Q
d. Diffuser Discharge Effluent Line	D(4)	N.A.	R	Q
4. Tank Level Indicating Devices				
a. Condensate Storage Tank	D*	N.A.	R	Q
b. Steam Generator Layup Tank	D*	N.A.	R	N.A.

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Table 3.3-12 - Radioactive Liquid Effluent Monitors

The minimum channels operable requirement has been revised to require one monitor for each essential raw cooling water discharge header.

TABLE 3.3-12

RADIOACTIVE LIQUID EFFLUENT MONITORING INSTRUMENTATION

INSTRUMENT	MINIMUM CHANNELS OPERABLE	ACTION
1. Radioactivity Monitors Providing alarm and Automatic Termination of Release		
a. Waste Disposal System Liquid Effluent Line (RE-90-120 and 121)	1	31
b. Steam Generator Blowdown Effluent Line (RE-90-124)	1	32
c. Condensate Demineralizer Regenerant Effluent Line (RE-90-225)	1	31
2. Radioactivity Monitors Providing Alarm But Not Providing Automatic Termination of Release		
a. Essential Raw Cooling Water Effluent Line (RE-90-133 & 90-140 or RE-90-134 & 90-141)	1/Discharge Header	33
b. Turbine Building Sump Effluent Line (RE-90-212)	1	33
c. Plant Liquid Discharge Line (RE-90-211)	1	33
3. Flow Rate Measurement Devices		
a. Waste Disposal System Liquid Radwaste Effluent Line	1	34
b. Condensate Demineralizer Regenerant Effluent Line	1	34
c. Steam Generator Blowdown Effluent Line	1	34
d. Diffuser Discharge Effluent Line	1	34
4. Tank Level Indicating Devices		
a. Condensate Storage Tank	1	35
b. Steam Generator Layup Tank*	1	35

*Required when connected to the Secondary Coolant System.

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Table 3.3-13 ACTION Statement 39 should be revised as indicated to better define the type of radioactivity analysis.

TABLE 3.3-13 (Continued)

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TABLE NOTATIONS

* At all times.

** During WASTE GAS HOLDUP SYSTEM operation.

*** During operation of the Containment Purge System, Auxiliary Building Gas Treatment System, or waste gas decay tank disposal.

**** At all times other than when the most recent Secondary Coolant System specific activity sample and analysis program gross radioactivity determination is less than or equal to 1×10^{-6} uCi/gm.

ACTION STATEMENTS

ACTION 37 - With the number of channels OPERABLE less than required by the Minimum Channels OPERABLE requirement, the contents of the tank(s) may be released to the environment for up to 14 days provided that prior to initiating the release:

a. At least two independent samples of the tank's contents are analyzed, and

b. At least two technically qualified members of the Facility staff independently verify the release rate calculations and discharge valve lineup.

Otherwise, suspend release of radioactive effluents via this pathway.

ACTION 38 - With the number of channels OPERABLE less than required by the Minimum Channels OPERABLE requirement, effluent releases via this pathway may continue for up to 30 days provided the flow rate is estimated at least once per 4 hours.

ACTION 39 - With the number of channels OPERABLE less than required by the Minimum Channels OPERABLE requirement, effluent releases via this pathway may continue for up to 30 days provided grab samples are taken at least once per 12 hours and these samples are analyzed for ~~radioactivity~~ within 24 hours.

noble gas gross radioactivity or an isotopic analysis is performed with LLD's as given in Table 4.11-2

ACTION 40 - With the number of channels OPERABLE less than required by the Minimum Channels OPERABLE requirement, operation of this Waste Gas Disposal System may continue for up to 7 days provided grab samples are collected at least once per 4 hours and analyzed within the following 4 hours to meet the requirements of Specification 3.11.2.5. With the hydrogen and oxygen monitors inoperable, be in at least HOT STANDBY within 6 hours.

ACTION 41 - With the number of channels OPERABLE less than required by the Minimum Channels OPERABLE requirement, effluent releases via the affected pathway may continue for up to 30 days provided that samples are continuously collected with auxiliary sampling equipment as required in Table 4.11-2.

ACTION 42 - With the number of channels OPERABLE less than required by the Minimum Channels OPERABLE requirement, immediately suspend PURGING or VENTING of radioactive effluents via this pathway.

Table 3.3-13 - Radioactive Gaseous Effluent Monitors

The applicability requirements have been revised. The waste gas holdup monitor is only required to be operable during waste gas holdup system operation. The containment purge exhaust monitors are only required to be operable during operation of the purge system.

TABLE 3.3-13

RADIOACTIVE GASEOUS EFFLUENT MONITORING INSTRUMENTATION

INSTRUMENT	MINIMUM CHANNELS OPERABLE	APPLICABILITY	ACTION
1. WASTE GAS HOLDUP SYSTEM (RE-90-118)			
a. Noble Gas Activity Monitor - Providing Alarm and Automatic Termination of Release	1	**	37
b. Effluent System Flow Rate Measuring Device	1	**	38
2. WASTE GAS HOLDUP SYSTEM Explosive Gas Monitoring System			
a. Hydrogen Monitor	1	**	40
b. Oxygen Monitor	1	**	40
3. Condenser Vacuum Exhaust System (RE-90-119)			
a. Noble Gas Activity Monitor	1	*	39
b. Effluent System Flow Rate Measuring Device	1	*	38
c. Monitor Flow Rate Measuring Device	1	*	38
d. Iodine Sampler	1	****	41
e. Particulate Sampler	1	****	41
f. Sampler Flow Rate Measuring Device	1	****	38
4. Shield Building Exhaust System (RE-90-400)			
a. Noble Gas Activity Monitor	1	***	39
b. Iodine Sampler	1	***	41
c. Particulate Sampler	1	***	41
d. Effluent System Flow Rate Measuring Device	1	***	38
e. Sampler Flow Rate Measuring Device	1	***	38
f. Monitor Flow Rate Measuring Device	1	***	38

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TABLE 3.3-13 (Continued)

RADIOACTIVE GASEOUS EFFLUENT MONITORING INSTRUMENTATION

INSTRUMENT	MINIMUM CHANNELS OPERABLE	APPLICABILITY	ACTION
5. Auxiliary Building Ventilation System And Fuel Handling Area Ventilation System (RE-90-101)			
a. Noble Gas Activity Monitor - Providing Alarm and Automatic Termination of Release	1	*	39
b. Iodine Sampler	1	*	41
c. Particulate Sampler	1	*	41
d. Effluent System Flow Rate Measuring Device	1	*	38
e. Sampler Flow Rate Measuring Device	1	*	38
f. Monitor Flow Rate Measuring Device	1	*	38
6. Service Building Ventilation System (RE-90-132)			
a. Noble Gas Activity Monitor	1	*	39
b. Effluent System Flow Rate Measuring Device	1	*	38
c. Monitor Flow Rate Measuring Device	1	*	38
7. Containment Purge and Exhaust System (RE-90-130/131) Noble Gas Activity Monitor - Providing Alarm and Automatic Termination of Release	1	****	42

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TABLE 3.3-13 (Continued)

TABLE NOTATIONS

* At all times.

** During WASTE GAS HOLDUP SYSTEM operation.

*** During operation of the Containment Purge System, Emergency Gas Treatment System, Auxiliary Building Gas Treatment System, or waste gas decay tank disposal.

**** At all times other than when the most recent Secondary Coolant System specific activity sample and analysis program gross radioactivity determination is less than or equal to 1 x 10^{-6} μCi/gm.

***** During operation of the Containment Purge System

ACTION STATEMENTS

ACTION 37 - With the number of channels OPERABLE less than required by the Minimum Channels OPERABLE requirement, the contents of the tank(s) may be released to the environment for up to 14 days provided that prior to initiating the release:

a. At least two independent samples of the tank's contents are analyzed, and

b. At least two technically qualified members of the Facility staff independently verify the release rate calculations and discharge valve lineup.

Otherwise, suspend release of radioactive effluents via this pathway.

ACTION 38 - With the number of channels OPERABLE less than required by the Minimum Channels OPERABLE requirement, effluent releases via this pathway may continue for up to 30 days provided the flow rate is estimated at least once per 4 hours.

ACTION 39 - With the number of channels OPERABLE less than required by the Minimum Channels OPERABLE requirement, effluent releases via this pathway may continue for up to 30 days provided grab samples are taken at least once per 12 hours and these samples are analyzed for radioactivity within 24 hours.

ACTION 40 - With the number of channels OPERABLE less than required by the Minimum Channels OPERABLE requirement, operation of this Waste Gas Disposal System may continue provided grab samples are collected at least once per batch transfer to a waste gas decay tank and at least once per 4 hours and analyzed within the following 4 hours to meet the requirements of Specification 3.11.2.5. With either the hydrogen or oxygen monitor inoperable for more than 7 days or with both oxygen and hydrogen monitors inoperable, prepare and submit to the Commission within 30 days, pursuant to Specification 6.9.2, a Special Report that identifies the cause(s) for the inoperability, action(s) taken to restore the monitor(s) to OPERABLE status, and a summary description of action(s) taken to prevent recurrence.

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REACTOR COOLANT SYSTEM - SPECIFIC ACTIVITY - SPECIFICATION 3.4.8 - (PAGE 3/4 4-26) AND BASES 3/4.4.8 - (PAGE B 3/4 4-7)

Delete the Action Statement on Page 3/4 4-26 requiring submittal of a special report on the results of the specific activity analysis. As noted in section 3.10 of NUREG-1024 'Technical Specifications - Enhancing the Safety Impact' this action exists solely for the purpose of gathering data. The NRC Task Group on Technical Specifications stated that the 'technical specifications should not contain such requirements.'

Also, delete the reference to this information submittal in the Bases.

3/4.4.8 SPECIFIC ACTIVITY

LIMITING CONDITION FOR OPERATION

3.4.8 The specific activity of the reactor coolant shall be limited to:

a. Less than or equal to 1 microCurie per gram DOSE EQUIVALENT I-131, and

b. Less than or equal to $100/\bar{E}$ microCuries per gram of gross radioactivity.

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

ACTION:

MODES 1, 2 and 3*:

a. With the specific activity of the reactor coolant greater than 1 microCurie per gram DOSE EQUIVALENT I-131 but within the Allowable limit (below and to the left of the line) shown on Figure 3.4-1, operation may continue for up to 48 hours provided that the cumulative operating time under these circumstances does not exceed 800 hours in any consecutive 12-month period. The provisions of Specification 3.0.4 are not applicable;

b. With the total cumulative operating time at a reactor coolant specific activity greater than 1 microCurie per gram DOSE EQUIVALENT I-131 exceeding 500 hours in any consecutive 6-month period, prepare and submit a Special Report to the Commission pursuant to Specification 6.9.2 within 30 days indicating the number of hours above this limit. The provisions of Specification 3.0.4 are not applicable;

DELETE

c. With the specific activity of the reactor coolant greater than 1 microCurie per gram DOSE EQUIVALENT I-131 for more than 48 hours during one continuous time interval or exceeding the limit line shown on Figure 3.4-1, be in at least HOT STANDBY with T_{avg} less than 500°F within 6 hours; and

d. With the specific activity of the reactor coolant greater than $100/\bar{E}$ microCuries per gram of gross radioactivity, be in at least HOT STANDBY with T_{avg} less than 500°F within 6 hours.

---

* With T_{avg} greater than or equal to 500°F.

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REACTOR COOLANT SYSTEM

LIMITING CONDITION FOR OPERATION

ACTION (Continued)

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

With the specific activity of the reactor coolant greater than 1 microCurie per gram DOSE EQUIVALENT I-131 or greater than 100/Ē microCuries per gram of gross radioactivity, perform the sampling and analysis requirements of Item 4.a) of Table 4.4-4 until the specific activity of the reactor coolant is restored to within its limits. ~~In the Semi-Annual Report, pursuant to Specification 6.9.1.4, submit the results of the specific activity analyses together with the following information:~~

a. Reactor power history starting 48 hours prior to the first sample in which the limit was exceeded;

b. Results of: (1) the last isotopic analysis for radioiodines performed prior to exceeding the limit, (2) analysis while limit was exceeded, and (3) one analysis after the radioiodine activity was reduced to less than limit including for each isotopic analysis, the date and time of sampling and the radioiodine concentrations;

c. Clean-up flow history starting 48 hours prior to the first sample in which the limit was exceeded;

d. History of degassing operations, if any, starting 48 hours prior to the first sample in which the limit was exceeded; and

e. The time duration when the specific activity of the reactor coolant exceeded 1 microCurie per gram DOSE EQUIVALENT I-131.

DELETE

SURVEILLANCE REQUIREMENTS

4.4.8 The specific activity of the reactor coolant shall be determined to be within the limits by performance of the sampling and analysis program of Table 4.4-4.

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SPECIFIC ACTIVITY (Continued)

Based upon the above considerations for excluding certain radionuclides from the sample analysis, the allowable time of 2 hours between sample taking and completing the initial analysis is based upon a typical time necessary to perform the sampling, transport the sample, and perform the analysis of about 90 minutes. After 90 minutes the gross count should be made in a reproducible geometry of sample and counter having reproducible beta or gamma self-shielding properities. The counter should be reset to a reproducible efficiency versus energy. It is not necessary to identify specific nuclides. The radiochemical determination of nuclides should be based on multiple counting of the sample with typical counting basis following sampling of less than 1 hour, about 2 hours, about 1 day, about 1 week and about 1 month.

Reducing T_{avg} to less than 500°F with a reduction of RCS pressure prevents the release of activity should a steam generator tube rupture since the saturation pressure of the reactor coolant is below the lift pressure of the atmospheric steam relief valves. The Surveillance Requirements provide adequate assurance that excessive specific activity levels in the reactor coolant will be detected in sufficient time to take corrective action. ~~Information obtained on iodine spiking will be used to assess the parameters associated with spiking phenomena~~. A reduction in frequency of isotopic analyses following power changes may be permissible if justified by the data obtained.

3/4.4.9 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:

a. 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:

   1. 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

3/4 4-26 & 3/4 4-27	Delete unnecessary reporting requirements as recommended in NUREG 1024 and draft revision 5 to the Westinghouse Standard Technical Specifications.

REACTOR COOLANT SYSTEM

3/4.4.8 SPECIFIC ACTIVITY

LIMITING CONDITION FOR OPERATION

3.4.8 The specific activity of the reactor coolant shall be limited to:

a. Less than or equal to 1 microCurie per gram DOSE EQUIVALENT I-131, and

b. Less than or equal to 100/$\bar{E}$ microCuries per gram of gross radioactivity.

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

ACTION:

MODES 1, 2 and 3*:

a. With the specific activity of the reactor coolant greater than 1 microCurie per gram DOSE EQUIVALENT I-131 but within the Allowable limit (below and to the left of the line) shown on Figure 3.4-1, operation may continue for up to 48 hours provided that the cumulative operating time under these circumstances does not exceed 800 hours in any consecutive 12-month period. The provisions of Specification 3.0.4 are not applicable;

DELETE

b. With the total cumulative operating time at a reactor coolant specific activity greater than 1 microCurie per gram DOSE EQUIVALENT I-131 exceeding 500 hours in any consecutive 6-month period, prepare and submit a Special Report to the Commission pursuant to Specification 6.9.2 within 30 days indicating the number of hours above this limit. The provisions of Specification 3.0.4 are not applicable;

c. With the specific activity of the reactor coolant greater than 1 microCurie per gram DOSE EQUIVALENT I-131 for more than 48 hours during one continuous time interval or exceeding the limit line shown on Figure 3.4-1, be in at least HOT STANDBY with T_{avg} less than 500°F within 6 hours; and

d. With the specific activity of the reactor coolant greater than 100/$\bar{E}$ microCuries per gram of gross radioactivity, be in at least HOT STANDBY with T_{avg} less than 500°F within 6 hours.

* With T_{avg} greater than or equal to 500°F.

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ACTION (Continued)

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

With the specific activity of the reactor coolant greater than 1 microCurie per gram DOSE EQUIVALENT I-131 or greater than 100/Ē microCuries per gram of gross radioactivity, perform the sampling and analysis requirements of Item 4.a) of Table 4.4-4 until the specific activity of the reactor coolant is restored to within its limits. ~~For the Annual Report, pursuant to Specification 6.9.1.4, submit the results of the specific activity analyses together with the following information:~~

a. Reactor power history starting 48 hours prior to the first sample in which the limit was exceeded;

b. Results of: (1) the last isotopic analysis for radioiodines performed prior to exceeding the limit, (2) analysis while limit was exceeded, and (3) one analysis after the radioiodine activity was reduced to less than limit including for each isotopic analysis, the date and time of sampling and the radioiodine concentrations;

c. Clean-up flow history starting 48 hours prior to the first sample in which the limit was exceeded;

d. History of degassing operations, if any, starting 48 hours prior to the first sample in which the limit was exceeded; and

e. The time duration when the specific activity of the reactor coolant exceeded 1 microCurie per gram DOSE EQUIVALENT I-131.

DELETE

SURVEILLANCE REQUIREMENTS

4.4.8 The specific activity of the reactor coolant shall be determined to be within the limits by performance of the sampling and analysis program of Table 4.4-4.

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EMERGENCY CORE COOLING SYSTEM - ACCUMULATORS - SPECIFICATION 3.5.1.1 - PAGE 3/4 5-1) AND SPECIFICATION 3.5.1.2 (PAGE 3/4 5-3)

Specifications 3.5.1.1 and 3.5.1.2 are only applicble above 1,000 and 1,900 psig pressurizer pressure respectively; thus, the Action Statements should only require reducing pressure below these respective values. This is consistent with Specification 3.0.3 which states that the unit must be placed in a mode in which the LCO is not applicable within the specified times.

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3/4.5 EMERGENCY CORE COOLING SYSTEMS

3/4.5.1 ACCUMULATORS

COLD LEG INJECTION

LIMITING CONDITION FOR OPERATION

3.5.1.1 Each Cold Leg Injection Accumulator System shall be OPERABLE with:

a. The isolation valve open,

b. A contained borated water volume of between 7617 and 8033 gallons,

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

d. A nitrogen cover-pressure of between 385 and 447 psig.

APPLICABILITY: MODES 1, 2, and 3*.

ACTION:

a. With one Cold Leg Injection Accumulator System inoperable, except as a result of a closed isolation valve, restore the inoperable accumulator to OPERABLE status within ~~1 hour~~ or be in at ~~least HOT STANDBY~~ within the next 6 hours and ~~in HOT SHUTDOWN~~ within the following 6 hours.
be below 1000 psig Pressurizer pressure

b. With one Cold Leg Injection Accumulator System inoperable due to the isolation valve ~~being closed, either~~ immediately open the isolation valve or be in at least HOT STANDBY within 6 hours and ~~in HOT SHUTDOWN~~ within the following 6 hours.
be below 1000 psig Pressurizer pressure

SURVEILLANCE REQUIREMENTS

4.5.1.1.1 Each Cold Leg Injection Accumulator System shall be demonstrated OPERABLE:

a. At least once per 12 hours by:

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

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

*Pressurizer pressure above 1000 psig.

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LIMITING CONDITION FOR OPERATION

3.5.1.2 Each Upper Head Injection Accumulator System shall be OPERABLE with:

a. The isolation valves open,

b. The water-filled accumulator containing between 1805 and 1851 cubic feet of borated water having a boron concentration of between 1900 and 2100 ppm, and

c. The nitrogen-bearing accumulator pressurized to between 1185 and 1285 psig.

APPLICABILITY: MODES 1, 2, and 3.*

ACTION:

a. With the Upper Head Injection Accumulator System inoperable, except as a result of a closed isolation valve(s), restore ~~the Upper~~ Head Injection Accumulator System to OPERABLE ~~status~~ within 1 hour ~~or be~~ in at least HOT STANDBY within the next 6 hours and ~~in HOT SHUTDOWN~~ be below 1900 psig Pressurizer pressure within the following 6 hours.

b. With the Upper Head Injection Accumulator ~~System inoperable~~ due to ~~the isolation~~ valve(s) being closed, either ~~immediately open the~~ isolation valve(s) or be in HOT STANDBY within 6 hours and ~~in HOT SHUTDOWN~~ be below 1900 psig Pressurizer pressure within the next 6 hours.

SURVEILLANCE REQUIREMENTS

4.5.1.2 Each Upper Head Injection Accumulator System shall be demonstrated OPERABLE:

a. At least once per 12 hours by:

1) Verifying the contained borated water volume and nitrogen pressure in the accumulators, and

2) Verifying that each accumulator isolation valve is open.

*Pressurizer pressure above 1900 psig.

EMERGENCY CORE COOLING SYSTEMS - ACCUMULATORS - SPECIFICATION 4.5.1.1.1 - (PAGE 3/4 5-2)

SR 4.5.1.1.1.d should be deleted. SR 4.5.1.1.1.e requires that the cold leg accumulator isolation vlaves be verified open with power removed on a monthly basis whenever the Reactor Coolant System pressure is greater than 2000 psig. SR 4.5.1.1.1.d requires that the automatic opening signals for the cold leg accumulator valves be tested on an 18 month basis. TVA believes that this second test requirement is unnecessary because the valves are open and have power removed from them whenever the RCS pressure is greater than 2000 psig. The additional administrative controls required by SR 4.5.1.1.1.1.c were imposed by NRC because the automatic opening controls were not considered sufficiently reliable.

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SURVEILLANCE REQUIREMENTS (Continued)

b. At least once per 31 days and within 6 hours after each solution volume increase of greater than or equal to 2% of indicated span (1.6% of tank volume) by verifying the boron concentration of the accumulator solution,

c. At least once per 31 days when the RCS pressure is above 2000 psig by verifying that power to the isolation valve operator is disconnected by verifying the breaker is tagged open, and

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

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

~~2) Upon receipt of a Safety Injection test signal.~~

4.5.1.1.2 Each Cold Leg Injection Accumulator System water level and pressure channel shall be demonstrated OPERABLE:

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

b. At least once per 18 months by the performance of a CHANNEL CALIBRATION.

Pages 3/4 5-9 and 3/4 5-10

Concerning SI pump operation, the cold overpressure analysis considered only the operation of a charging pump. To prevent the possibility of a mass input from a safety injection pump occurring, the technical specifications require that all safety injection pumps be inoperable in those modes for which cold overpressure is a concern (proposed revisions to technical specification 3.5.3 attached). In addition, surveillance requirement 4.5.3.2 should be revised to permit testing of the safety injection pumps and filling of the cold leg accumulators whenever the pump must be incapable of causing a cold overpressure event (proposed revisions to surveillance requirement 4.5.3.2 attached).

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3/4.5.3 ECCS SUBSYSTEMS - $T_{avg} \leq 350°F$

LIMITING CONDITION FOR OPERATION

3.5.3 As a minimum, one ECCS subsystem comprised of the following shall be OPERABLE:

a. One OPERABLE centrifugal charging pump,#

b. One OPERABLE RHR heat exchanger,

c. One OPERABLE RHR pump, and

d. An OPERABLE flow path capable of taking suction from the refueling water storage tank upon being manually realigned and transferring suction to the containment sump during the recirculation phase of operation.

APPLICABILITY: MODE 4.

ACTION:

a. With no ECCS subsystem OPERABLE because of the inoperability of either the centrifugal charging pump or the flow path from the refueling water storage tank, restore at least one ECCS subsystem to OPERABLE status within 1 hour or be in COLD SHUTDOWN within the next 20 hours.

b. With no ECCS subsystem OPERABLE because of the inoperability of either the RHR heat exchanger or RHR pump, restore at least one ECCS subsystem to OPERABLE status or maintain the Reactor Coolant System T_{avg} less than 350°F by use of alternate heat removal methods.

c. In the event the ECCS is actuated and injects water into the Reactor Coolant System, a Special Report shall be prepared and submitted to the Commission pursuant to Specification 6.9.2 within 90 days describing the circumstances of the actuation and the total accumulated actuation cycles to date. The current value of the usage factor for each affected Safety Injection nozzle shall be provided in this Special Report whenever its value exceeds 0.70.

A maximum of one centrifugal charging pump ~~and one Safety Injection pump~~ shall be OPERABLE whenever the temperature of one or more of the RCS cold legs is less than or equal to 350°F.

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SURVEILLANCE REQUIREMENTS

4.5.3.1 The ECCS subsystem shall be demonstrated OPERABLE per the applicable requirements of Specification 4.5.2.

4.5.3.2 All charging pumps and Safety Injection pumps, except the above allowed OPERABLE pumps, shall be demonstrated inoperable at least once per 12 hours whenever ~~the temperature of~~ one or more ~~of the RCS cold legs is less than or equal to 350°F~~ by verifying that the pumps are in the pull-to-lock position ~~and~~ and/or the motor circuit breakers are tagged out, or the pump(s) is isolated from the RCS by a manually closed valve or by a motor-operated valve with the valve breaker tagged. Normal seal flow can be maintained at all times.

3/4 6-2

Specification 4.6.1.2 should be revised as indicated to remove the reference to ANSI N45.4-1972. TVA should have the flexibility to use any test method that meets the criteria specified in Appendix J to 10 CFR Part 50.

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LIMITING CONDITION FOR OPERATION

3.6.1.2 Containment leakage rates shall be limited to:

a. An overall integrated leakage rate of less than or equal to L_a, 0.25% by weight of the containment air per 24 hours at P_a, 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; and;

c. A combined bypass leakage rate of less than 0.25 L_a for all penetrations identified in Table 3.6-1 as secondary containment bypass leakage paths when pressurized to P_a.

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

ACTION:

With: (a) the measured overall integrated containment leakage rate exceeding 0.75 L_a, or (b) the measured combined leakage rate for all penetrations and valves subject to Types B and C tests exceeding 0.60 L_a, or (c) the combined bypass leakage rate exceeding 0.25 L_a, restore the overall integrated leakage rate to less than 0.75 L_a and the combined leakage rate for all penetrations and valves subject to Type B and C tests to less than 0.60 L_a, and the combined bypass leakage rate to less than 0.25 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 Part 50: ~~using the methods and provisions of ANSI N45.1-1972.~~

3/4 6-5 Typographical error.

TABLE 3.6-1

SECONDARY CONTAINMENT BYPASS LEAKAGE PATHS

PENETRATION	RELEASE LOCATION
X-67	Auxiliary Building
X-76	Auxiliary Building
X-77	Auxiliary Building
X-78	Auxiliary Building
X-81	Auxiliary Building
X-82	Auxiliary Building
X-83	Auxiliary Building
X-84A	Auxiliary Building
X-85A	Auxiliary Building
X-85B	Auxiliary Building
X-90	Auxiliary Building
X-91	Auxiliary Building
X-93	Auxiliary Building
X-94A/B	Auxiliary Building
X-94C	Auxiliary Building
X-95A/B	Auxiliary Building
X-95C	Auxiliary Building
X-110	Auxiliary Building
X-114	Auxiliary Building
X-115	Auxiliary Building
X-2A	Auxiliary Building
X-2B	Auxiliary Building
X-3	Auxiliary Building
X-40D	Auxiliary Building
X-56A	Auxiliary Building
X-57A	Auxiliary Building
X-58A	Auxiliary Building
X-59A	Auxiliary Building
X-60A	Auxiliary Building
X-61A	Auxiliary Building
X-62A	Auxiliary Building
X-63A	Auxiliary Building
X-92C	Auxiliary Building
X-~~101~~ 28	Auxiliary Building
X-105	Auxiliary Building
X-106	Auxiliary Building

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3/4 6-8

Surveillance Requiement 4.6.1.3.a should be revised as indicated. TVA has plans to install a continuous leakage monitoring system on the airlock door seals. The continuous monitoring system can be used in lieu of the individual test. The proposed wording allows for use of either method.

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SURVEILLANCE REQUIREMENTS

4.6.1.3 Each containment air lock shall be demonstrated OPERABLE:

a. Except for air locks using continuous Leakage Monitoring Systems, Within 72 hours following each closing, except when the air lock is being used for multiple entries, then at least once per 72 hours, by pressurizing the volume between the door seals to at least 6 psig for at least 30 seconds and verifying the leakage does not exceed 0.01 L_a;

b. By conducting overall air lock leakage tests at not less than P_a, 15 psig, and verifying the overall air lock leakage rate is within its limit:

1) At least once per 6 months,# and

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

c. At least once per 6 months by verifying that only one door in each air lock can be opened at a time.

#The provisions of Specification 4.0.2 are not applicable.
*This represents an exemption to Appendix J of 10 CFR Part 50.

Through discussions with NRC reviewers, TVA was informed that a purge valve leakage rate must be less than $0.01L_a$ unless a higher valve could be justified. Furthermore, a leakage rate of $0.05L_a$ was that maximum that would be allowed per valve. TVA was also informed that the justification must state that at $0.05L_a$ or some lower valve, the resilient seals must not fail catastrophically.

TVA has worked with the valve vendor, POSI-SEAL International, Inc. (PSI), to obtain this justification. The attached letter from PSI provides the required assurance that at $0.05L_a$ the valve seals will not fail catastrophically. TVA requests that the leakage limit per valve be increased from $0.01L_a$ to $0.05L_a$.

DE05:CHNG4.GT

CONTAINMENT VENTILATION SYSTEM

LIMITING CONDITION FOR OPERATION

3.6.1.9 Each containment purge supply and/or exhaust isolation valve shall be OPERABLE. The 24-inch valves at less than or equal to 70° open, the 8-inch valves, and the 12-inch valve(s) may be opened for up to ~~500~~ 2000 hours during a calendar year provided no more than one pair (one exhaust and one supply) is open at one time.

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

ACTION:

a. With the purge supply and/or exhaust isolation valve(s) open for more than ~~500~~ 2000 hours during a calendar year, close any open containment purge and/or exhaust isolaton valve or isolate the penetration(s) within 4 hours, otherwise be in at least HOT STANDBY within the next 6 hours, and in COLD SHUTDOWN within the following 30 hours.

b. With the 24-inch containment purge supply and/or exhaust isolation valve(s) at greater than 70° open, close the valve(s) or isolate the penetration(s) within 4 hours, otherwise be in at least HOT STANDBY within the next 6 hours, and in COLD SHUTDOWN within the following 30 hours.

c. With a containment purge supply and/or exhaust isolation valve(s) having a measured leakage rate in excess of the limits of Specifications 4.6.1.9.3, restore the inoperable valve(s) to OPERABLE status within 24 hours, otherwise be in at least HOT STANDBY within the next 6 hours, and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.6.1.9.1 Each 24-inch containment purge supply and/or exhaust isolation valve(s) shall be verified to be physically restricted to less than or equal to 70° open at least once per 31 days.

4.6.1.9.2 The cumulative time that all containment purge supply and/or exhaust isolation valves have been open during a calendar year shall be determined at least once per 7 days.

4.6.1.9.3 At least once per 3 months each containment purge supply and/or exhaust isolation valve with resilient material seals shall be demonstrated OPERABLE by verifying that the measured leakage rate is less than ~~0.01~~ 0.05 L_a when pressurized to P_a.

POSI-SEAL INTERNATIONAL, INC.

ROUTES 49 & US 95 NORTH STONINGTON CT 06359 203 599 1140 TELEX 966443

October 2, 1984
PSI No. 20.0.004.84

Tennessee Valley Authority
Watts Bar Nuclear Plant
P. O. Box 800
Spring City, TN 37381

Attention: Mr. W. T. Cottle
Site Director

Subject: Watts Bar Nuclear Plant
Posi-Seal Butterfly Valves
Leakage Limits

The purpose of this letter is to address TVA's request of August 22, 1984 pertaining to leakage limits.

The seals that Posi-Seal provided for the Watts Bar Nuclear Plant are soft seated, Tefzel and Urethane seals. Under normal operating conditions these seals should remain bubble tight. However, if an anomaly were to occur which resulted in a leakage rate of 12.50 SCFH, this leakage rate would not cause a catastrophic failure of the valve by damaging the valve seat. This statement is based on Posi-Seal's extensive experience in testing valves with various leakage rates and Posi-Seal's experience with valves in the field.

If you should need any additional information please let me know.

Sincerely,

John G. Rodgers
Supervisor of Engineering

jh

Containment Isolation Valves - Table 3.6.2

The majority of the containment isolation valves listed in Table 3.6-2 are associated with non-essential systems, i.e., systems that need not functon to effectively operate the plant. The only safety related function of these valves is to close on various containment isolation signals. If the containment penetrations associated with these valves are isolated (via closed blind flange) the safety function is accomplished. This position is accepted by NRC as evidenced by the ACTION STATEMENT which allows continued operation as long as an inoperable penetration is isolated. However, the ACTION STATEMENT as it is now written does not allow mode changes via the requirements of specification 3.0.4.

Since the safety function is accomplished when the affected penetration is isolated, we propose that the requirements of specification 3.0.4 not be applicable to inoperable valves that are not required open for plant operation as long as the requirements of parts b or c of the ACTION STATEMENT are satisfied. We suggest that the exempted valves be identified by a footnote as we have done in the attached marked up Table 3.6-2.

The attached marked up table has footnotes added to exempt the majority of valves from the provisions of specification 3.0.4. This will allow entry into Modes 1, 2, 3, or 4 as long as those valves not required to be open for plant operation are closed with the power removed from the valve operator. This will ensure the valve remains closed. Also, to be consistent with the ACTION STATEMENT, closure of one automatic valve in the penetration with its power removed or closure of one manual valve or blind flange is an acceptable alternative.

Below is a brief discussion of each group of valves for which we are requesting exemption from 3.0.4. Each valve discussed is identified on the attached drawings.

Phase A Isolation

Steam generator blowdown isolation valves FCV-1-7, 14, 25, 32, 181, 182, 183, and 184. These are inboard and outboard steam generator blowdown isolation valves for each steam generator as identified on drawing 47W801-2. These valves are not required to be open during normal or accident conditions. Their safety function is fulfilled as long as the valve is isolated. Any chemistry or sampling constraints due to these valves being closed will be handled under technical specification 3.7.1.4 and 6.8.5.

Chilled water to the incore instrument room coolers isolation valves FCV-31C-305, 306, 308, 309, 326, 327, 329, and 330. This system provides cooling to the incore instrument room. Since there are two redundant systems, any and all valves on one package can be isolated as long as the other system's valves are OPERABLE. This is handled by note ## in Table 3.6-2.

Reactor coolant system sample outlet header isolation valves FCV-43-22 and 23. These valves are not required to be open during plant operation. Any constraints on RCS sampling will be handled under technical specification 3.4.7.

Steam generator blowdown sample isolation valves FCV-43-54D, 55, 56D, 58, 59D, 61, 63D, and 64. There are separate lines with inboard and outboard isolation valves for each steam generator. These lines are not required to be open during plant operation. Any sampling constraints due to isolation of these lines will be handled under technical specifications 3.7.1.4 and 6.8.5.

Glycol inlet and outlet isolation valves FCV-61-96, 97, 110, and 122 to the ice condenser floor coolers are not required to be open for plant operation. Any ice condenser temperature problem that may be a result of this is handled under technical specification 3.6.5.2.

Glycol inlet and outlet isolation valves FCV-61-191, 192, 193, and 194 to the ice condenser air handling units are not required to be open for plant operation. Any ice condenser temperature problems that may be a result of this isolation is handled under technical specification 3.6.5.2.

Valves FCV-62, 72, 73, 74, and 76 are the inboard parallel isolation valves for the letdown line. Only one of the isolation valves associated with the 75 gpm letdown orifices need be open for normal operational letdown. FCV-62-72, 73, and 74 will have the ## note to handle this constraint. Letdown is not required for any safety related function.

Containment isolation valves FCV-63-23, 71, and 84 are used for cold leg accumulator filling and draining and various check valve testing. They are not required to be open for normal power operation. Any loss of ability to fill or drain the accumulators and/or test certain check valves are handled under technical specifications 3.5.1.1 and 3.4.6.2.

FCV-63-64 is the isolation valve for the nitrogen supply to the cold leg accumulator. This valve need not be open during operation. The system it serves is covered under technical specification 3.5.1.1.

FCV-68-305 is the nitrogen supply line for the pressurizer relief tank. This valve is not required for safe operation or shutdown of the plant. Any constraints on the normal operation of the plant that may arise from isolation of this line will be handled via plant procedures.

FCV-68-307 and 308 are the gas analyzer sample lines for the pressurizer relief tank. These valves are not required for safe operation or shutdown of the plant. Any constraints on the normal operation of the plant that may arise from isolation of this line will be handled via plant procedures.

FCV-70-143 and 85 are the isolation valves for component cooling water to excess letdown heat exchanger. This heat exchanger need not be operable during plant operation and, thus, these valves may be isolated.

FCV-77-9, 10, 16, 17, 18, 19, and 20 are the reactor coolant drain tank (RCDT) pump discharge, RCDT sample line to the gas analyzer, RCDT waste gas vent header and nitrogen supply isolation valves, respectively. These valves are not required to be open for the safe operation or shutdown of the plant. Any constraints on the normal operation of the plant that may arise from isolation of these lines will be handled via plant operating procedures.

FCV-77-127 and 128 are the floor and equipment drain sump pump discharge isolation valves. These lines are not required to be open for the safe operation or shutdown of the plant. Any constraint on normal operations that may arise due to this line being isolated will be handled via plant operating procedures.

FCV-87-7, 8, 9, 10, and 11 are isolation valves for UHI test line (check valve testing). These valves are not required to be open during plant operation. Any constraints on check valve testing due to any of these valves being inoperable and isolated is handled under technical specification 3.4.6.2.

FCV-43-2, 3, 11, and 12 are pressurizer sample lines isolation valves. These valves are not required to be open during plant operation. Any constraint on RCS sampling due to isolation of these lines will be handled under technical specification 3.4.7.

FCV-43-34 and 35 are cold leg accumulator sample line isolation valves. These valves are not required to be open during plant operation. Any constraints on accumulator sampling will be handled under technical specification 3.5.1.1.

FCV-43-75 and 77 are the isolation valves for the continuous boron analyser. This system is not very reliable or accurate and, thus, will most likely not be used. This system is not required to operate.

Phase B Isolation

All the 67 series valves are containment isolation valves for the essential raw cooling water supply to the lower compartment, upper compartment, reactor coolant pump motor, and control rod drive mechanism coolers. These systems are not directly required to function during plant operation. Their isolation could cause a rise in containment temperature. However, the limits on containment temperature are handled under technical specification 3.6.1.5. It should be recognized that most of these systems are redundant and, thus, a portion of them can be inoperable (i.e., isolated) without the containment temperature being adversely effected.

Phase A - Containment Vent Isolation

All the 30 series valves are containment purge system isolation valves. These valves are normally not open and are actually restricted in the time allowed to be open by technical specification 3.6.1.9. They are not directly required to be open for plant operation. Any adverse affect on containment temperature or pressure due to unavailability of these purge paths (which is unlikely due to the redundant paths) is covered by technical specifications 3.6.1.5 and 3.6.1.4.

FCV-90-113, 114, 115, 116, and 117 are the isolation valves for the upper compartment particulate, iodine, and gas monitor. This monitor is not required to be OPERABLE and, thus, this path is not required to be open during plant operation.

Valve Functions

The functions for several valves have been corrected to properly identify the valves.

Isolation Times

The isolation times for the outboard steam generator blowdown isolation valves, the outboard letdown isolation valve, component cooling water to the excess letdown heat exchanger, essential raw cooling water to the lower compartment coolers, and component cooling water to the reactor coolant pump oil coolers, have been increased to reflect actual valve performance.

This change will have no effect on offsite dose because the service water piping will contain water at a pressure greater than the peak calculated containment pressure and the steam generator blowdown lines are not exposed to the containment environment. These lines are not explicitly modeled in the accident analyses. Instead, valve times indicative of proper valve performance are listed.

WATTS BAR - UNIT 1

TABLE 3.6-2

CONTAINMENT ISOLATION VALVES

VALVE NUMBER	FUNCTION	MAXIMUM ISOLATION TIME (Seconds)
1. Phase "A" Isolation		
FCV-1-7*#	SG Blowdown	10
FCV-1-14*#	SG Blowdown	10
FCV-1-25*#	SG Blowdown	10
FCV-1-32*#	SG Blowdown	10
FCV-1-181*#	SG Blowdown	~~10~~ 15
FCV-1-182*#	SG Blowdown	~~10~~ 15
FCV-1-183*#	SG Blowdown	~~10~~ 15
FCV-1-184*#	SG Blowdown	~~10~~ 15
FCV-30-134	Cont. to Annulus ΔP	10
FCV-30-135	Cont. to Annulus ΔP	10
FCV-31C-305##	CW-Inst Room Clrs	10
FCV-31C-306##	CW-Inst Room Clrs	10
FCV-31C-308##	CW-Inst Room Clrs	10
FCV-31C-309##	CW-Inst Room Clrs	10
FCV-31C-326##	CW-Inst Room Clrs	10
FCV-31C-327##	CW-Inst Room Clrs	10
FCV-31C-329##	CW-Inst Room Clrs	10
FCV-31C-330##	CW-Inst Room Clrs	10
FCV-43-22#	Sample RC Outlet Hdrs	10
FCV-43-23#	Sample RC Outlet Hdrs	10
FCV-43-54D#	SG Blow Dn Sample Line ~~Stm Gen No. 1 Bldn Isol Vlv~~	10
FCV-43-56D#	" ~~Stm Gen No. 2 Bldn Isol Vlv~~	10
FCV-43-59D#	" ~~Stm Gen No. 3 Bldn Isol Vlv~~	10
FCV-43-63D#	" ~~Stm Gen No. 4 Bldn Isol Vlv~~	10
FCV-43-55#	SG Blow Dn Sample Line	10
FCV-43-58#	SG Blow Dn Sample Line	10
FCV-43-61#	SG Blow Dn Sample Line	10
FCV-43-64#	SG Blow Dn Sample Line	10
FCV-61-96#	Gylcol Inlet to Floor Cooler	30
FCV-61-97#	Gylcol Inlet to Floor Cooler	30
FCV-61-110#	Gylcol Outlet to Floor Cooler	30

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TABLE 3.6-2 (Continued)

CONTAINMENT ISOLATION VALVES

VALVE NUMBER	FUNCTION	MAXIMUM ISOLATION TIME (Seconds)
1. Phase "A" Isolation (Cont.)		
FCV-61-122 #	Gylcol Outlet to Floor Cooler	30
FCV-61-191 #	Ice Condenser - Gylcol In	30
FCV-61-192 #	Ice Condenser - Gylcol In	30
FCV-61-193 #	Ice Condenser - Gylcol Out	30
FCV-61-194 #	Ice Condenser - Gylcol Out	30
FCV-62-61	RCP Seals	10
FCV-62-63	RCP Seals	10
FCV-62-72 ##	Letdown Line	10
FCV-62-73 ##	Letdown Line	10
FCV-62-74 ##	Letdown Line	10
FCV-62-76 #	Letdown Line	10
FCV-62-77	Letdown Line	~~10~~ 20
FCV-63-23 #	~~Accum to Hold Up Tank~~ SI pump to Accum	10
FCV-63-64 #	WDS N_2 to Accum	10
FCV-63-71 #	Accum to Hold Up Tank	10
FCV-63-84 #	Accum to Hold Up Tank	10
FCV-68-305 #	WDS N_2 to PRT	10
FCV-68-307 #	PRT to Gas Analyzer	10
FCV-68-308 #	PRT to Gas Analyzer	10
FCV-70-85 #	CCS from Excess Lt Dn Hx	10
FCV-70-143 #	CCS to Excess Lt Dn Hx	~~60~~ 66
FCV-77-9 #	RCDT Pump Disch	10
FCV-77-10 #	RCDT Pump Disch	10
FCV-77-16 #	RCDT to Gas Analyzer	10
FCV-77-17 #	RCDT to Gas Analyzer	10
FCV-77-18 #	RCDT and PRT to V H	10
FCV-77-19 #	RCDT and PRT to V H	10
FCV-77-20 #	RCDT N_2 Supply	10
FCV-77-127 #	Floor Sump Pump Disch	10
FCV-77-128 #	Floor Sump Pump Disch	10
FCV-81-12 #	Primary Water Makeup	10
FCV-87-7 #	UHI Test Line	10
FCV-87-8 #	UHI Test Line	10
FCV-87-9 #	UHI Test Line	10

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TABLE 3.6-2 (Continued)

CONTAINMENT ISOLATION VALVES

VALVE NUMBER	FUNCTION	MAXIMUM ISOLATION TIME (Seconds)
1. Phase "A" Isolation (Cont.)		
FCV-87-10* #	UHI Test Line	10
FCV-87-11* #	UHI Test Line	10
FCV-26-240	Fire Protection Isol.	≤ 20
FCV-26-243	Fire Protection Isol.	≤ 20
FCV-43-2 #	Sample Przr Steam Space	≤ 5
FCV-43-3 #	Sample Przr Steam Space	≤ 5
FCV-43-11 #	Sample Przr Liquid	≤ 5
FCV-43-12 #	Sample Przr Liquid	≤ 5
FCV-43-34 #	Accum Sample	≤ 5
FCV-43-35 #	Accum Sample	≤ 5
FCV-43-75 #	Boron Analyzer	≤ 5
FCV-43-77 #	Boron Analyzer	≤ 5
2. Phase "B" Isolation		
FCV-32-80	Train A Control Air Isolation	≤ 10
FCV-32-102	Train B Control Air Isolation	≤ 10
FCV-32-110	Non-Essential Control Air Isolation	≤ 10
FCV-67-83 #	ERCW - LWR Cmpt, ~~Clrs~~ RCP Motor, and CRDM Clrs	≤ ~~60~~ 66
FCV-67-87 #	ERCW - LWR Cmpt, ~~Clrs~~ "	≤ ~~60~~ 66
FCV-67-88 #	ERCW - LWR Cmpt, ~~Clrs~~	≤ ~~60~~ 66
FCV-67-91 #	ERCW - LWR Cmpt, ~~Clrs~~	≤ ~~60~~ 66
FCV-67-95 #	ERCW - LWR Cmpt, ~~Clrs~~	≤ ~~60~~ 66
FCV-67-96 #	ERCW - LWR Cmpt, ~~Clrs~~	≤ ~~60~~ 66
FCV-67-99 #	ERCW - LWR Cmpt, ~~Clrs~~	≤ ~~60~~ 66
FCV-67-103 #	ERCW - LWR Cmpt, ~~Clrs~~	≤ ~~60~~ 66
FCV-67-104 #	ERCW - LWR Cmpt, ~~Clrs~~	≤ ~~60~~ 66
FCV-67-107 #	ERCW - LWR Cmpt, ~~Clrs~~	≤ ~~60~~ 66
FCV-67-111 #	ERCW - LWR Cmpt, ~~Clrs~~	≤ ~~60~~ 66
FCV-67-112 #	ERCW - LWR Cmpt, ~~Clrs~~	≤ ~~60~~ 66

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TABLE 3.6-2 (Continued)

CONTAINMENT ISOLATION VALVES

VALVE NUMBER	FUNCTION	MAXIMUM ISOLATION TIME (Seconds)
2. Phase "B" Isolation (Cont.)		
FCV-67-130 #	ERCW - Up Cmpt Clrs	≤ ~~60~~ 66
FCV-67-131 #	ERCW - Up Cmpt Clrs	≤ ~~60~~ 66
FCV-67-133 #	ERCW - Up Cmpt Clrs	≤ ~~60~~ 66
FCV-67-134 #	ERCW - Up Cmpt Clrs	≤ ~~60~~ 66
FCV-67-138 #	ERCW - Up Cmpt Clrs	≤ ~~60~~ 66
FCV-67-139 #	ERCW - Up Cmpt Clrs	≤ ~~60~~ 66
FCV-67-141 #	ERCW - Up Cmpt Clrs	≤ ~~60~~ 66
FCV-67-142 #	ERCW - Up Cmpt Clrs	≤ ~~60~~ 66
FCV-67-295 #	ERCW - Up Cmpt Clrs	≤ ~~60~~ 66
FCV-67-296 #	ERCW - Up Cmpt Clrs	≤ ~~60~~ 66
FCV-67-297 #	ERCW - Up Cmpt Clrs	≤ ~~60~~ 66
FCV-67-298 #	ERCW - Up Cmpt Clrs	≤ ~~60~~ 66
FCV-70-87	RCP Thermal Barrier Ret	≤ ~~60~~ 66
FCV-70-89	CCS from RCP Oil Coolers	≤ ~~60~~ 66
FCV-70-90	RCP Thermal Barrier Ret	≤ ~~60~~ 66
FCV-70-92	CCS from RCP Oil Coolers	≤ ~~60~~ 66
FCV-70-134	To RCP Thermal Barriers	≤ ~~60~~ 66
FCV-70-140	CCS to RCP Oil Coolers	≤ ~~60~~ 66
3. Phase "A" Containment Vent Isolation		
FCV-30-7 #	Upper Compt Purge Air Supply	≤ 4
FCV-30-8 #	Upper Compt Purge Air Supply	≤ 4
FCV-30-9 #	Upper Compt Purge Air Supply	≤ 4
FCV-30-10 #	Upper Compt Purge Air Supply	≤ 4
FCV-30-14 #	Lower Compt Purge Air Supply	≤ 4
FCV-30-15 #	Lower Compt Purge Air Supply	≤ 4
FCV-30-16 #	Lower Compt Purge Air Supply	≤ 4
FCV-30-17 #	Lower Compt Purge Air Supply	≤ 4

TABLE 3.6-2 (Continued)

CONTAINMENT ISOLATION VALVES

VALVE NUMBER	FUNCTION	MAXIMUM ISOLATION TIME (Seconds)
3. Phase "A" Containment Vent Isolation (Cont.)		
FCV-30-19 #	Inst Room Purge Air Supply	≤ 4
FCV-30-20 #	Inst Room Purge Air Supply	≤ 4
FCV-30-37 #	Lower Compt Pressure Relief	≤ 4
FCV-30-40 #	Lower Compt Pressure Relief	≤ 4
FCV-30-50 #	Upper Compt Purge Air Exh	≤ 4
FCV-30-51 #	Upper Compt Purge Air Exh	≤ 4
FCV-30-52 #	Upper Compt Purge Air Exh	≤ 4
FCV-30-53 #	Upper Compt Purge Air Exh	≤ 4
FCV-30-56 #	Lower Compt Purge Air Exh	≤ 4
FCV-30-57 #	Lower Compt Purge Air Exh	≤ 4
FCV-30-58 #	Inst Room Purge Air Exh	≤ 4
FCV-30-59 #	Inst Room Purge Air Exh	≤ 4
FCV-90-107	Cntmt Bldg LWR Compt Air Mon	≤ 5
FCV-90-108	Cntmt Bldg LWR Compt Air Mon	≤ 5
FCV-90-109	Cntmt Bldg LWR Compt Air Mon	≤ 5
FCV-90-110	Cntmt Bldg LWR Compt Air Mon	≤ 5
FCV-90-111	Cntmt Bldg LWR Compt Air Mon	≤ 5
FCV-90-113 #	Cntmt Bldg Up Compt Air Mon	≤ 5
FCV-90-114 #	Cntmt Bldg Up Compt Air Mon	≤ 5
FCV-90-115 #	Cntmt Bldg Up Compt Air Mon	≤ 5
FCV-90-116 #	Cntmt Bldg Up Compt Air Mon	≤ 5
FCV-90-117 #	Cntmt Bldg Up Compt Air Mon	≤ 5

*Not subject to Type C leakage tests.

The provisions of specification 3.0.4 are not applicable if the requirements of items b or c of the ACTION STATEMENT are met.

The provisions of specification 3.0.4 are not applicable if the requirements of items b or c of the ACTION STATEMENT are met and at least one other path of the affected system is ~~inoperable~~ OPERABLE.

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Specification 3.6.4.3 requires the operability of two trains of the primary containment hydrogen mitigation system. Because of this system, the hydrogen recombiners become less important. The action statement should allow for inoperability of both recombiners for a limited period of time, rather than an immediate shutdown via specification 3.0.3 because of the redundant ignitor system.

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LIMITING CONDITION FOR OPERATION

3.6.4.2 Two independent Hydrogen Recombiner Systems shall be OPERABLE.

APPLICABILITY: MODES 1 and 2.

ACTION:

a. With one Hydrogen Recombiner System inoperable, restore the inoperable system to OPERABLE status within 30 days or be in at least HOT STANDBY within the next 6 hours.

b. With both Hydrogen Recombiner System inoperable, restore at least one of the inoperable systems to OPERABLE status within 7 days or be in at least HOT STANDBY within the next 6 hours.

SURVEILLANCE REQUIREMENTS

4.6.4.2 Each Hydrogen Recombiner System shall be demonstrated OPERABLE:

a. At least once per 6 months by verifying during a Recombiner System functional test that the minimum heater sheath temperature increases to greater than or equal to 700°F within 90 minutes. Upon reaching 700°F, increase the power setting to maximum power for 2 minutes and verify that the power meter reads greater than or equal to 60 kW~~; and~~

b. At least once per 18 months by:

1) Performing a CHANNEL CALIBRATION of all recombiner instrumentation and control circuits,

2) Verifying through a visual examination that there is no evidence of abnormal conditions within the recombiners enclosure (i.e., loose wiring or structural connections, deposits of foreign materials, etc.), and

3) Verifying the integrity of all heater electrical circuits by performing a resistance to ground test following the above required functional test. The resistance to ground for any heater phase shall be greater than or equal to 10,000 ohms.

Changes to reflect the results of the reduced ice weight analysis performed by Westinghouse. The analysis and FSAR revisions will be forwarded in the near future.

CONTAINMENT SYSTEMS

3/4.6.5 ICE CONDENSER

ICE BED

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LIMITING CONDITION FOR OPERATION

3.6.5.1 The ice bed shall be OPERABLE with:

a. The stored ice having a boron concentration of at least 1800 ppm boron as sodium tetraborate and a pH of 9.0 to 9.5,

b. Flow channels through the ice condenser,

c. A maximum ice bed temperature of less than or equal to 27°F,

d. A total ice weight of at least ~~2,719,500~~ 2,360,875 pounds at a 95% level of confidence, and

e. 1944 ice baskets.

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

ACTION:

With the ice bed inoperable, restore the ice bed to OPERABLE status within 48 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.6.5.1 The ice condenser shall be determined OPERABLE:

a. At least once per 12 hours by using the Ice Bed Temperature Monitoring System to verify that the maximum ice bed temperature is less than or equal to 27°F,

b. At least once per 9 months by:

1) Chemical analyses which verify that at least nine representative samples of stored ice have a boron concentration of at least 1800 ppm as sodium tetraborate and a pH of 9.0 to 9.5 at 20°C;

2) Weighing a representative sample of at least 144 ice baskets and verifying that each basket contains at least ~~1399~~ 1214 lbs of ice. The representative sample shall include six baskets from each of the 24 ice condenser bays and shall be constituted of

1214

one basket each from Radial Rows 1, 2, 4, 6, 8, and 9 (or from the same row of an adjacent bay if a basket from a designated row cannot be obtained for weighing) within each bay. If any basket is found to contain less than ~~1399~~ pounds of ice, a representative sample of 20 additional baskets from the same bay shall be weighed. The minimum average weight of ice from the 20 additional baskets and the discrepant basket shall not be less than ~~1399~~ pounds/basket at a 95% level of confidence.

1214

~~The ice~~ condenser shall also be subdivided into 3 groups of baskets, as follows: Group 1 - Bays 1 through 8, Group 2 - Bays 9 through 16, and Group 3 - Bays 17 through 24. The minimum average ice weight of the sample baskets from Radial Rows 1, 2, 4, 6, 8, and 9 in each group shall not be less than ~~1399~~ pounds/basket at a 95% level of confidence.

1214

The minimum total ice condenser ice weight at a 95% level of confidence shall be calculated using all ice basket weights determined during this weighing program and shall not be less than ~~2,719,500~~ pounds; and

2,360,875

3) Verifying, by a visual inspection of at least two flow passages per ice condenser bay, that the accumulation of frost or ice on flow passages between ice baskets, past lattice frames, through the intermediate and top deck floor grating, or past the lower inlet plenum support structures and turning vanes is restricted to a thickness of less than or equal to 0.38 inch. If one flow passage per bay is found to have an accumulation of frost or ice with a thickness of greater than or equal to 0.38 inch, a representative sample of 20 additional flow passages from the same bay shall be visually inspected. If these additional flow passages are found acceptable, the surveillance program may proceed considering the single deficiency as unique and acceptable. More than one restricted flow passage per bay is evidence of abnormal degradation of the ice condenser.

c. At least once per 40 months by lifting and visually inspecting the accessible portions of at least two ice baskets from each one-third of the ice condenser and verifying that the ice baskets are free of detrimental structural wear, cracks, corrosion or other damage. The ice baskets shall be raised at least 10 feet for this inspection.

3/4.6.4 COMBUSTIBLE GAS CONTROL

The OPERABILITY of the equipment and systems required for the detection and control of hydrogen gas ensures that this equipment will be available to maintain the hydrogen concentration within containment below its flammable limit during post-LOCA conditions, Either recombiner unit is capable of controlling the expected hydrogen generation associated with: (1) zirconium-water reactions, (2) radiolytic decomposition of water, and (3) corrosion of metals within containment. These Hydrogen Control Systems are consistent with the recommendations of Regulatory Guide 1.7, "Control of Combustible Gas Concentrations in Containment Following a LOCA," March 1971.

The Hydrogen Mixing Systems are provided to ensure adequate mixing of the containment atmosphere following a LOCA. This mixing action will prevent localized accumulations of hydrogen from exceeding the flammable limit.

The OPERABILITY of at least 33 of 34 ignitors per train (66 of 68 for both trains) in the Hydrogen Mitigation System will maintain an effective coverage throughout the containment provided the two inoperable ignitors are not on corresponding redundant circuits which provide coverage for the same region. This system of ignitors will initiate combustion of any significant amount of hydrogen released after a degraded core accident. This system is to ensure burning in a controlled manner as the hydrogen is released instead of allowing it to be ignited at high concentrations by a random ignition source.

3/4.6.5 ICE CONDENSER

The requirements associated with each of the components of the ice condenser ensure that the overall system will be available to provide sufficient pressure suppression capability to limit the containment peak pressure transient to less than 15 psig during LOCA conditions.

3/4.6.5.1 ICE BED

The OPERABILITY of the ice bed ensures that the required ice inventory will: (1) be distributed evenly through the containment bays, (2) contain sufficient boron to preclude dilution of the containment sump following the LOCA, and (3) contain sufficient heat removal capability to condense the Reactor Coolant System volume released during a LOCA. These conditions are consistent with the assumptions used in the safety analyses.

The minimum weight figure of ~~1399~~ 1214 pounds of ice per basket contains a 10% conservative allowance for ice loss through sublimation which is a factor of 10 higher than assumed for the ice condenser design and 1% for weighing accuracies. In the event that observed sublimation rates are equal to or lower than design predictions after 3 years of operation, the minimum ice basket weight may be adjusted downward. In addition, the number of ice baskets required to be weighed each 9 months may be reduced after 3 years of operation if such a reduction is supported by observed sublimation data.

Table 3.7-1 Steam Line Safety Valves

The orifice size has been changed from a nominal value to the actual dimension.

TABLE 3.7-1

STEAM LINE SAFETY VALVES PER LOOP

VALVE NUMBER					
LOOP 1	LOOP 2	LOOP 3	LOOP 4	LIFT SETTING (± 1%)*	ORIFICE SIZE
1-522	1-517	1-512	1-527	1224 psig	14.2 ~~16~~ square inches
1-523	1-518	1-513	1-528	1215 psig	14.2 ~~16~~ square inches
1-524	1-519	1-514	1-529	1205 psig	14.2 ~~16~~ square inches
1-525	1-520	1-515	1-530	1195 psig	14.2 ~~16~~ square inches
1-526	1-521	1-516	1-531	1185 psig	14.2 ~~16~~ square inches

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

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Page 3/4 7-5 Auxiliary Feedwater Valve Alignments

In a letter from L. M. Mills to E. Adensam dated September 15, 1982 (A27 820915 002) TVA requested relief from the requirement to verify that each non-automatic valve in the auxiliary feedwater flow path that is not locked, sealed, or otherwise secured in position is in its correct position. The draft technical specifications were revised by NRC shortly after receipt of TVA's request. This test requirement was reinstated by NRC in the final draft copy of the technical specifications without notice or explanation. TVA again requests that this requirement be deleted. The basis for the request is provided below.

The performance of this valve alignment check every seven days requires a substantial manpower investment. TVA believes that this alignment check provides no additional assurance that auxiliary feedwater will be available when needed. This is based on TVA's system design. The flow requirements are that one pump must deliver flow to at least two steam generators. TVA's design utilizes three pumps (two motor driven and one steam driven). The pumps share a common suction line to the condensate storage tank (CST). The line contains series manual isolation valves. However, the correct position of these manual valves is not required because each pump is also provided with a separate suction source from the essential raw cooling water system. The transfer from the CST to ERCW is done automatically on low suction pressure. These features are included in the technical specifications.

Each pump virtually has an independent flow path to each steam generator because no manual or automatic valves are installed in common discharge piping. Hence, the misposition of any single valve in the discharge path would only prevent flow from one pump from reaching one steam generator. As stated above, the flow requirements are that one of three pumps must provide flow to two of four steam generators.

A recently added surveillance requirement (4.7.1.2.2) requires that expected flow to each steam generator must be demonstrated for each pump after any extended outage. This requirement coupled with the fact that the auxilary feedwater system function cannot be rendered inoperable by the mispositioning of a manual isolation valve provides the necessary assurance the auxiliary feedwater flow will be available when needed. The requirement to check valve alignments for manual valves every seven days should be deleted. This proposal has the benefit to TVA of reducing shift manpower requirements.

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SURVEILLANCE REQUIREMENTS (Continued)

~~3) Verifying that each non-automatic valve in the flow path that is not locked, sealed, or otherwise secured in position is in its correct position; and~~

3 ~~4~~) Verifying that each automatic valve in the flow path is OPERABLE whenever the Auxiliary Feedwater System is placed in automatic control or when above 10% RATED THERMAL POWER.

b. At least once per 18 months by:

1) Verifying that each automatic valve in the flow path actuates to its correct position upon receipt of a Safety Injection test signal and a Low Auxiliary Feedwater Pump Suction Pressure test signal, and

2) Verifying that each auxiliary feedwater pump starts as designed automatically upon receipt of each Auxiliary Feedwater Actuation test signal.

4.7.1.2.2 An auxiliary feedwater flow path to each steam generator shall be demonstrated OPERABLE following each COLD SHUTDOWN of greater than 30 days prior to entering MODE 2 by verifying expected flow to each steam generator.

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Specification 4.7.10.3 requires the submittal of an annual report if removable contamination from a sealed source or fission detector is greater than or equal to .005 microcurie. This reporting requirement is contrary to NUREG-1024, Section 3.10 which states,

> "Some of the requirements in the Standard Technical Specifications (STS) are for the purpose of collecting information and do not add to operational safety. The Technical Specifications should not contain such requirements."

The scope of this annual report is not specified which leads to the conclusion that Specification 4.7.10.3 is included as a punitive requirement which is also cited in NUREG-1024, Section 3.2 as an STS problem area,

> "The ACTION Statements of some technical specifications seem to be structured as a punitive measure against utilities that have safety equipment out of service rather than as a function of the significance of the equipment outage from the standpoint of risk to the public."

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SURVEILLANCE REQUIREMENTS (Continued)

b. Stored sources not in use - Each sealed source and fission detector shall be tested prior to use or transfer to another licensee unless tested within the previous 6 months. Sealed sources and fission detectors transferred without a certificate indicating the last test date shall be tested prior to being placed into use; and

c. Startup sources and fission detectors - Each sealed startup source and fission detector shall be tested within 31 days prior to being subjected to core flux or installed in the core and following repair or maintenance to the source.

~~4.7.10.3 Reports - A report shall be prepared and submitted to the Commission on an annual basis if sealed source or fission detector leakage tests reveal the presence of greater than or equal to 0.005 microCurie of removable contamination.~~

Fire Suppression System - Specification 3.7.11.1

Surveillance requirement 4.7.11.1.a has been revised to allow for pump operabilty verification during any mode of pump operation. This will eliminate the need to realign the pump to recirculation mode if it is running in service water mode.

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3/4.7.11 FIRE SUPPRESSION SYSTEMS

FIRE SUPPRESSION WATER SYSTEM

LIMITING CONDITION FOR OPERATION

3.7.11.1 The Fire Suppression Water System shall be OPERABLE with:

a. At least three fire suppression pumps, each with a capacity of 1590 gpm at 330 feet of head, with their discharge aligned to the fire suppression header, and

b. An OPERABLE flow path capable of taking suction from the forebay and transferring the water through distribution piping with OPERABLE sectionalizing control or isolation valves to the yard hydrant curb valves, the standpipe hose valves, and the first valve upstream of the water flow device on each Spray System required to be OPERABLE per Specifications 3.7.11.2 and 3.7.11.4.

APPLICABILITY: At all times.

ACTION:

a. With one pump inoperable, restore at least three pumps to OPERABLE status within 7 days or provide an alternate backup pump or supply. The provisions of Specifications 3.0.3 and 3.0.4 are not applicable.

b. With the Fire Suppression Water System otherwise inoperable establish a backup Fire Suppression Water System within 24 hours.

SURVEILLANCE REQUIREMENTS

4.7.11.1 The Fire Suppression Water System shall be demonstrated OPERABLE:

a. At least once per 31 days on a STAGGERED TEST BASIS by starting each pump and operating it for at least 15 minutes ~~on recirculation flow~~,

b. At least once per 31 days by verifying that each testable valve (manual, power-operated, or automatic) in the flow path is in its correct position,

c. At least once per 6 months by performance of a system flush,

d. At least once per 12 months by cycling each non-self indicating testable valve in the flow path through at least one complete cycle of full travel, 3/4 7-39 The exemptions to specification 3.0.3 and 3.0.4 are necessary to prevent unnecessary and unexpected draconian interpretations for common area temperatures. This is consistent with draft revision 5 to the Westinghouse Standard Technical Specifications.

PLANT SYSTEMS

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3/4.7.13 AREA TEMPERATURE MONITORING

LIMITING CONDITION FOR OPERATION

3.7.13 The temperature limit of each area given in Table 3.7-4 shall not be exceeded for more than 8 hours or by more than 30°F.

APPLICABILITY: Whenever the affected equipment in an affected area is required to be OPERABLE.

ACTION:

a. With one or more areas exceeding the temperature limit(s) given in Table 3.7-4 for more than 8 hours, prepare and submit a Special Report to the Commission within 30 days, pursuant to Specification 6.9.2, that provides a record of the cumulative time and the amount by which the temperature in the affected area(s) exceeded the limit(s) and an analysis to demonstrate the continued OPERABILITY of the affected equipment. The provisions of Specification 3.0.3 and 3.0.4 are not applicable.

b. With one or more areas exceeding the temperature limit(s) given in Table 3.7-4 by more than 30°F, prepare and submit a Special Report as required by ACTION a. above and within 4 hours either restore the area(s) to within the temperature limit(s) or declare the affected equipment in the affected area(s) inoperable.

SURVEILLANCE REQUIREMENTS

4.7.13 The temperature in each of the areas given in Table 3.7-4 shall be determined to be within its limit at least once per 12 hours.

WATTS BAR NUCLEAR PLANT UNITS 1 AND 2
DIESEL GENERATOR ROOM TEMPERATURE

By letter dated March 6, 1984 from T. M. Novak to H. G. Parris, TVA was notified of action needed to resolve NRC concerns related to the Watts Bar Nuclear Plant diesel engine cooling water keep warm system. This action included installation of an alarm in the diesel generator (DG) room set to annunciate in the main control room when the room temperature drops below 65°F. In conjuction with this, TVA would be required to declare the D/G inoperable and take the appropriate action to restore the temperature to 65°F or above.

In lieu of a remote temperature monitoring program, TVA will utilize Surveillance Instruction (SI) 7.46 to provide notification to operations personnel of DG room temperature. The existing SI requirement of monitoring the DG room temperature once per shift will be expanded to specify additional evaluation and action to reestablish a minimum DG room temperature if the recorded temperature is below that set minimum. The alternative of using periodic surveillance as opposed to remote monitoring was proposed on Sequoyah Nuclear Plant by my letter to you dated November 10, 1981 (see attachment A) and was approved by letter dated February 4, 1982 from R. L. Tedesco to H. G. Parris (see attachment B). Use of the SI for Watts Bar should, therefore, resolve the NRC concerns related to indication of DG room temperature. With respect to the specific minimum DG room temperature to be used for initiation of TVA action, we offer the following.

Included with the March 6, 1984 letter was a letter dated December 9, 1981 from M. J. Fleckenstein to R. J. Giardina which provided the NRC with information related to the DG standby immersion heater system. The March 6, 1984 letter stated that the information provided by the Electro-Motive Division (EMD) of General Motors Corporation (December 9, 1981 letter), ". . .has shown that satisfactory performance of the cooling water preheat system is based on maintaining a diesel engine temperature of 65°F or higher." TVA has reviewed the EMD information and does not agree that this is a valid assumption.

The EMD test was originally intended to show that the engine water would not be overheated by the immersion heater. Therefore, the ambient temperature at which the test was conducted was either arbitrary or conservatively set such that it would not offset the actual effects of the immersion heater. In either case, it should not be considered to be the lowest ambient temperature for which DG reliability can be assured; only that 65°F is an acceptable ambient temperature. The test does, however, verify that the remote areas of the DG (i.e., cylinder heads) were maintained at a temperature of 20°F over the ambient temperature, by the stand by immersion heater system. As specified by the EMD report, this was due to the fact that ". . .the cylinders are heated by warm water traveling down the water manifold and rising to displace the cold water." "The cold water must also return through the manifold since the normal (shutdown) water level is below the water outlet pipe." This is apparent from curve 3 of the subject report which shows that during the period between 16 and 24 hours, after equilibrium conditions had been reached, an increase in ambient temperature resulted in a corresponding increase in average cylinder temperature. Since this correlation is valid for the temperature range of interest, (40°F to 65°F) a DG room temperature of 40°F would result in a cylinder head temperature of no less than 60°F. This temperature, which is indicative of the lowest temperature of the critical DG components, is sufficient to assure reliable DG start.

Additional evidence of reliable DG start at temperatures below 65°F is provided by the cold start tests performed by Power Systems Division of Morrison-Knudsen Company. Attached is a data sheet showing the ambient temperatures for each of the 300 cold start tests and specific information on test No. 21 with details of the test procedure (see attachment C and D).

TVA believes that in conjunction with the above specified information, the fact that there is no historical evidence of a failure at DG start due to low ambient temperature, provides assurance of reliable DG start if the room temperature is maintained at 40°F or higher.

To summarize, TVA will revise SI 7.46 to require that the temperature of the four DG rooms be monitored once each shift in accordance with the proposed Tech Spec change to Table 3.7-4. In the event that the temperature falls below 40°F in any of the DG rooms, action will be taken per the action statement for specification 3.7.13. The revised SI 7.46 will also provide specific guidelines for remedial action.

TABLE 3.7-4

AREA TEMPERATURE MONITORING

	AREA	TEMPERATURE LIMIT (°F)
1.	Aux Bldg el 722 next to 480V Sd Bd transformer 1A2-A.	≤ 104
2.	Aux Bldg el 722 next to 480V Sd Bd transformer 1B1-B.	≤ 104
3.	Aux Bldg el 772 next to 480V Rx MOV Bd 1A2-A.	≤ 104
4.	Aux Bldg el 772 across from spare 125V vital battery charger 1-S.	≤ 104
5.	Aux Bldg el 772 next to 480V Rx MOV Bd 2A2-A.	≤ 104
6.	Aux Bldg el 772 next to 480V Sd Bd transformer 2A2-A.	≤ 104
7.	Aux Bldg el 772 next to 480V Sd Bd transformer 2B2-B.	≤ 104
8.	Aux Bldg el 772 next to 480V Rx MOV Bd 2B2-B.	≤ 104
9.	Aux Bldg el 772 U1 Mech Equip Room B.	≤ 104
10.	Sd Bd room el 757 U1 behind stairs S-A3.	≤ 104
11.	Sd Bd room el 757 U2 behind stairs S-A13.	≤ 104
12.	Refueling floor el 757 U1 beside Aux boration makeup tk.	≤ 104
13.	Aux Bldg el 737 U1 outside supply fan room.	≤ 104
14.	Aux Bldg el 713 U1 across from AFW pumps.	≤ 104
15.	Aux Bldg el 692 U1 outside AFW pump room door.	≤ 104
16.	Aux Bldg el 692 U2 near boric acid concentrate filter vault.	≤ 104
17.	Aux Bldg el 676 next to 0-L-629.	≤ 104
18.	Add Equip Bldg U1 el 729 between UHI accumulators.	≥ 75 ≤ 85
19.	Main Control Room south wall.	≤ 104
20.	Main Control Room across from 1-M-9.	≤ 104
21.	D/G Bldg el 742 2B-B D/G room on wall by battery charger.	≤ 120
22.	D/G Bldg el 760.5 next to 480V diesel Aux Bd 2B1-B.	≤ 120
23.	IPS el 741 next to 1A-A ERCW-MCC transformer and board.	≤ 120
24.	IPS el 741 in B train ERCW pump room.	≤ 120
25.	IPS el 741 next to 2A-A ERCW-MCC transformer and board.	≤ 120
26.	Computer room el 708 center of room.	≥ 65 ≤ 75
27.	North steam valve vault room U1 Morgan Temp Recorder.	≥ 80
28.	South steam valve vault room U1 Morgan Temp Recorder.	≥ 80
29	D/G BLDG el 742 1A-A D/G Room Near D/G SET	≥ 40
30	D/G BLDG el 742 1B-B D/G ROOM Near D/G SET	≥ 40
31	D/G BLDG el 742 2A-A D/G ROOM Near D/G SET	≥ 40
32	D/G BLDG el 742 2B-B D/G ROOM Near D/G SET	≥ 40

3/4 8-1, 3/4 8-2, 3/4 8-3, 3/4 8-4, 3/4 8-6, 3/4 8-7, 3/4 8-8, 3/4 8-9, 3/4 8-10, 3/4 8-11 and 3/4 8-12

Specifications 3.8.1.1 and 4.8.1.1.2 - For clarity revise where indicated to designate the diesel generator(s) as set(s).

Specification 3.8.1.1 ACTION Statements a., b., and d. - Revise as indicated in accordance with NRC Generic Letter 84-15.

Specification 3.8.1.1 ACTION Statement f. - Incorporate the proposed ACTION Statement to defer diesel starting when one or more diesels are inoperable solely because the fuel levels are below minimum. Twenty-four hours has been proposed to restore fuel levels before additional surveillance is required. TVA believes this approach is consistent with the philosophy expressed in NRC Generic Letter 84-15.

Surveillance Requirement 4.8.1.1 - Replace with the diesel generator reliability improvement program in accordance with NRC Generic Letter 84-15.

Surveillance Requirements 4.8.1.1.2.e and f - For bases see TVA submittal of June 19, 1984.

Surveillance Requirements 4.8.1.1.3.a.3 and 4.8.1.1.3.b - TVA has reviewed the battery Surveillance Requirements associated with the diesel generator batteries. The batteries consist of 57 cells. The minimum float is 2.2 volts per cell or 125.4 volts across the bank. The float voltage range is 2.20 volts to 2.25 volts. The minimum voltage is 1.75 volts per cell and the maximum voltage is 2.39 volts per cell. These result in a minimum and maximum voltage across the bank of 99.75 volts and 136.23 volts, respectively. The Final Safety Analysis Report specifies requirements for the battery chargers. These must meet or exceed the battery requirements specified in the Technical Specifications.

Surveillance Requirements 4.8.2.1.a.2 and 4.8.2.1.b - TVA has reviewed the battery Surveillence Requirements associated with the diesel generator batteries. The batteries consists of 60 cells. The critical voltage parameters are the same as those listed for the diesel generator batteries. The float voltage and overvoltage limits should be revised as indicated. TVA has reviewed the battery charger capacity. The value specified in Surveillance Requirement 4.8.2.1.c.4 is consistent with the expected load on the charger during normal operation.

Surveillance Requirement 4.8.1.1.2.a.4.c - Delete the requirement to start the diesel by a loss of offsite power signal coincident with a safety injection signal. The actual logic circuit start circuit consists of three sets of contacts wired in series. One set is the safety injection signal and two sets are the loss of offiste power signal. Opening any one of the contacts will result in a diesel start. The coincident test requires that at least two of the contacts be opened at the same time. The test really is unnecessary and repetitive. The wiring diagram for this position of the circuit is shown in FSAR Figure 8.3-29. Relay K609 is the safety injection signal and relays 27D1AX and 27D1AY are the loss of offsite power signal.

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3/4.8 ELECTRICAL POWER SYSTEMS

3/4.8.1 A.C. SOURCES

OPERATING

LIMITING CONDITION FOR OPERATION

3.8.1.1 As a minimum, the following A.C. electrical power sources shall be OPERABLE:

a. Two physically independent circuits between the offsite transmission network and the Onsite Class 1E Distribution System, and

b. Four separate and independent diesel generator sets, each with:

1) Two diesels driving a common generator,

2) Two separate engine-mounted fuel tanks containing a minimum volume of 250 gallons of fuel in each tank,

3) A separate 7 day fuel storage tank containing a minimum volume of 62,000 gallons of fuel,

4) A separate fuel transfer pump, and

5) A separate 125-volt DC distribution panel, 125-volt D.C. battery bank and associated charger.

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

ACTION:

offsite

a. With either an offsite circuit or diesel generator set of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the remaining A.C. sources by performing Specification~~s~~ 4.8.1.1.1a. ~~and 4.8.1.1.2a.4)~~ within 1 hour and at least once per 8 hours thereafter; restore at least two offsite circuits and four diesel generator sets 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.

and specification 4.8.1.1.2.a.4 within 24 hours;

offsite

b. With one offsite circuit and one diesel generator set of the above required A.C. electrical power sources inoperable, demonstrate the OPERABILITY of the remaining A.C. sources by performing Specifications 4.8.1.1.1a. ~~and 4.8.1.1.2a.4)~~ within 1 hour and at least once per 8 hours thereafter; restore at least one of the inoperable sources to OPERABLE status within 12 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours. Restore at least two offsite circuits and four diesel generator sets to OPERABLE status within 72 hours from the time of initial loss or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

and specification 4.8.1.1.2.a.4 within 8 hours;

c. With one diesel generator set inoperable in addition to ACTION a. or b. above, verify that:

the requirements of

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LIMITING CONDITION FOR OPERATION

ACTION (Continued)

1. All required systems, subsystems, trains, components and devices that depend on the remaining OPERABLE diesel generator sets as a source of emergency power are also OPERABLE, and

2. When in MODE 1, 2, or 3, the steam-driven auxiliary feedwater pump is OPERABLE.

If these conditions are not satisfied within 2 hours, be in at least HOT STANDBY within the next 6 hours, and in COLD SHUTDOWN within the following 30 hours.

d. With two of the above required offsite A.C. circuits inoperable, demonstrate the OPERABILITY of four diesel generator sets by performing Specification 4.8.1.1.2a.4) within ~~1~~ 8 hour and at least once per 8 hours thereafter, unless the diesel generator sets are already operating; restore at least one of the inoperable offsite sources to OPERABLE status within 24 hours or be in at least HOT STANDBY within the next 6 hours. With only one offsite source restored, restore at least two offsite circuits to OPERABLE status within 72 hours from time of initial loss or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

e. With two or more diesel generator sets inoperable, demonstrate the OPERABILITY of two offsite A.C. circuits by performing Specification 4.8.1.1.1a. within 1 hour and at least once per 8 hours thereafter; restore at least Diesel Generator Sets 1A-A and 2A-A or 1B-B and 2B-B 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. Restore at least four diesel generator sets to OPERABLE status within 72 hours from time of initial loss or be in least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

INSERT Action f.

SURVEILLANCE REQUIREMENTS

4.8.1.1.1 Each of the above required independent circuits between the offsite transmission network and the onsite Class 1E Distribution System shall be:

a. Determined OPERABLE at least once per 7 days by verifying correct breaker alignments, indicated power availability, and

b. Demonstrated OPERABLE at least once per 18 months during shutdown by transferring (manually and automatically) power supply from the normal circuit to the alternate circuit.

4.8.1.1.2 Each diesel generator set shall be demonstrated OPERABLE:

a. In accordance with the frequency specified in Table 4.8-1 on a STAGGERED TEST BASIS by:

1) Verifying the fuel level in the engine-mounted fuel tank,

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Proposed Action Statement F

With one or more diesel generator~~s~~ sets inoperable solely because the fuel levels in one or more tanks are below the minimum, restore the levels to above the minimum within 24 hours; otherwise comply with ACTION Statements a, b, or e above as applicable.

SURVEILLANCE REQUIREMENTS (Continued)

2) Verifying the fuel level in the 7-day fuel storage tank,

3) Verifying the fuel transfer pump starts and transfers fuel from the 7-day fuel storage tank to the engine-mounted tank,

4) Verifying the diesel starts from ambient condition and accelerates to 900 ± 18 rpm in less than or equal to 10 seconds.* The generator voltage and frequency shall be 6900 ± 690 volts and 60 ± 1.2 Hz within 10 seconds* after the start signal. The diesel generator shall be started for this test by using one of the following signals:

a) Manual, or

b) Simulated loss-of-offsite power by itself, or

~~c) Simulated loss-of-offsite power in conjunction with an ESF actuation test signal, or~~

c ~~d~~) An ESF actuation test signal by itself.

5) Verifying the generator is synchronized, loaded to greater than or equal to 4400 kW in less than or equal to 60 seconds,* and operates with a load greater than or equal to 4400 kW for at least 60 minutes, and

6) Verifying the diesel generator is aligned to provide standby power to the associated shutdown boards.

b. At least once per 31 days and after each operation of the diesel where the period of operation was greater than or equal to 1 hour by removing accumulated water from the engine-mounted fuel tanks;

c. At least once per 31 days by checking for and removing accumulated water from the 7-day fuel oil storage tanks;

d. By sampling new fuel oil in accordance with ASTM-D4057 prior to addition to storage tanks and:

1) By verifying in accordance with the tests specified in ASTM-D975-81 prior to addition to the storage tanks that the sample has:

a) An API Gravity of within 0.3 degrees at 60°F, or a specific gravity of within 0.0016 at 60/60°F, when compared to the supplier's certificate, or an absolute specific gravity at 60/60°F of greater than or equal to 0.83 but less than or equal to 0.89, or an API gravity of greater than or equal to 27 degrees but less than or equal to 39 degrees;

*These diesel generator starts from ambient conditions shall be performed only once per 184 days in these surveillance tests and all other engine starts for the purpose of this surveillance testing shall be preceded by an engine prelube period and/or other warmup procedures recommended by the manufacturer so that the mechanical stress and wear on the diesel engine is minimized.

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SURVEILLANCE REQUIREMENTS (Continued)

3) The resistance of each cell to terminal connection is less than or equal to 150×10^{-6} ohms.

~~4.8.1.1.4 Reports - All diesel generator failures, valid or non-valid, shall be reported to the Commission pursuant to Specification 6.9.1. Report of diesel generator failures shall include the information recommended in Regulatory Position C.3.b of Regulatory Guide 1.108, Revision 1, August 1977. If the number of failures in the last 100 valid tests (on a per nuclear unit basis) is greater than or equal to 7, the report shall be supplemented to include the additional information recommended in Regulatory Position C.3.b of Regulatory Guide 1.108, Revision 1, August 1977.~~

Insert SR 4.8.1.1.4

4.8.1.1.4 Diesel Generator Reliability Improvement Program

As a minimum the Reliability Improvement Program report for NRC audit shall include:

(a) a summary of all tests (valid and invalid) that occurred within the time period over which the last 20/100 valid tests were performed

(b) analysis of failures and determination of root causes of failures

(c) evaluation of each of the recommendations of NUREG/CR-0660, Enhancement of Onsite Emergency Diesel Generator Reliability in Operating Reactors, with respect to their application to the Plant

(d) identification of all actions taken or to be taken to (1) correct the root causes of failures defined in (b) above and (2) achieve a general improvement of diesel generator reliability

(e) the schedule for implementation of each action from (d) above

(f) an assessment of the existing reliability of electric power to engineered-safety-feature equipment

Once a licensee has prepared and maintained an initial report detailing the diesel generator reliability improvement program at his site, as defined above, the licensee need prepare only a supplemental report within 30 days after each failure during a valid demand for so long as the affected diesel generator unit contiues to violate the criteria (3/20 or 6/100) for the reliability improvement program remedial action. The supplemental report need only update the failure/demand history for the affected diesel generator unit since the last report for that diesel generator. The supplemental report shall also present an analysis of the failure(s) with a root cause determination, if possible, and shall delineate any further procedural, hardware or operational changes to be incorporated into the site diesel generator improvement program and the schedule for implementation of those changes.

In addition to the above, submit a yearly data report on the diesel generator reliability.

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TABLE 4.8-1

DIESEL GENERATOR TEST SCHEDULE

NUMBER OF FAILURES IN LAST ~~100~~ 20 VALID TESTS*	TEST FREQUENCY
≤ 1	At least once per 31 days
≥ 2	At least once per ~~14~~ 7 days**
~~3~~	~~At least once per 7 days~~
~~≥ 4~~	~~At least once per 3 days~~

---

*Criteria for determining number of failures and number of valid tests shall be in accordance with Regulatory Position C.2.e of Regulatory Guide 1.108, Revision 1, August 1977, where the ~~last 100 tests are~~ number of tests and failures are determined on a per ~~nuclear unit~~ diesel generator set basis. For the purposes of this test schedule, only valid tests conducted after the OL issuance date shall be included in the computation of the "last ~~100~~ 20 valid tests." Entry into this test schedule shall be made at the 31-day test frequency.

** This test frequency shall be maintained until seven consecutive failure free demands have been performed and the number of failures in the last 20 valid demands has been reduced to one or less.

TABLE 4.8-2

ADDITIONAL RELIABILITY ACTIONS

No. of failures in last 20 valid test	No of failures in last 100 valid tests	Action
3	6	Within ~~14~~ 30 days prepare and maintain a report for NRC audit, describing the diesel generator reliability ~~improvement~~ program implemented at the site, in accordance with Surveillance Requirement 4.8.1.1.4. ~~Minimum requirements for the report are indicated in Attachment 1 to this table.~~
5	11	Declare the diesel generator inoperable and perform ~~. Perform~~ a requalification test program for the affected diesel generator pursuant to the Attachment to this table. ~~Requalification test program requirements are indicated in Attachment 2 to this table.~~

3/4 8-6	The 2000 hour rating for the diesel generators is 4840 kw. NRC changed this value to 4400 kw without explanation. It should be corrected.

FINAL DRAFT

these limits during this test. Within 5 minutes after completing this 24-hour test, perform Specification 4.8.1.1.2d.6)b);*

8) Verifying that the auto-connected loads to each diesel generator do not exceed the 2000-hour rating of ~~4400~~ 4840 kW;

9) Verifying the diesel generator's capability to:

   a) Synchronize with the offsite power source while the generator is loaded with its emergency loads upon a simulated restoration of offsite power,

   b) Transfer its loads to the offsite power source, and

   c) Be restored to its standby status.

10) Verifying that the automatic load sequence timers are OPERABLE and their Setpoints are within the specified bands; and

11) Verifying that the following diesel generator lockout features prevent diesel generator starting only when required:

   a) Engine overspeed, or

   b) 86 GA lockout relay, or

   c) Emergency stop.

e. At least once per 10 years or after any modifications which could affect diesel generator interdependence by starting all diesel generators simultaneously, during shutdown, and verifying that all diesel generators accelerate to 900 ± 18 rpm in less than or equal to 10 seconds; and

*If Specification 4.8.1.1.2d.6)b) is not satisfactorily completed, it is not necessary to repeat the preceding 24-hour test. Instead, the diesel generator may be operated at 4400 kW for 1 hour or until operating temperature has stabilized.

Diesel Generator Fuel Oil System Hydrostatic Pressure Test

Technical specification 4.8.1.1.2.h.2 requires that those portions of the diesel fuel oil system designed to Section III, Subsection ND of the ASME Code be hydrostatically tested every ten years. TVA requests that this specification be deleted. The only portions of the diesel fuel oil system designed to this section of the ASME Code are those listed on FSAR drawings 9.5-20 (revised by amendment 52) as TVA Class C. This piping includes the flameproof atmospheric vent lines and the supply and overflow return lines between the 7-day tank and diesel generator day tanks.

ASME Code Case N-240 exempts from hydrostatic testing piping whose only function is to transport fluids to and from spray ponds, lakes, reservoirs, or tanks which are open to the atmosphere. The TVA fuel oil system piping in question is used to transport fluid (liquid and vapor) between tanks that are open (vented) to the atmosphere.

NRC has found ASME Code Case N-240 acceptable for use. This fact is documented in Regulatory Guide 1.84, Revision 22, as issued in July 1984.

SURVEILLANCE REQUIREMENTS (Continued)

h. At least once per 10 years by:

Draining each 7-day fuel storage tank, removing the accumulated sediment and cleaning the tank using a sodium hypochlorite solution, and

~~2) Performing a pressure test of those portions of the diesel fuel oil system designed to Section III, subsection ND of the ASME Code at a test pressure equal to 110% of the system design pressure.~~

4.8.1.1.3 The 125-volt D.C. distribution panel, 125-volt D.C. battery bank and associated charger for each diesel generator shall be demonstrated OPERABLE:

a. At least once per 7 days by verifying:

1) Correct breaker alignment, indicated power availability and voltage on the distribution panels greater than or equal to 118 volts,

2) That each battery bank and charger meet the Category A limits in Table 4.8-2 of Specification 4.8.2.1, and

3) That the total battery terminal voltage is greater than or equal to 125 volts on float charge.

b. At least once per 92 days and within 7 days after a battery discharge with a battery terminal voltage below 100 volts or a battery overcharge with a battery terminal voltage above 136 volts by:

1) Verifying that the parameters in Table 4.8-2 of Specification 4.8.2.1 meet the Category B limits,

2) Verifying there is no visible corrosion at either terminals or connectors, or the cell to terminal connection resistance of these items is less than 150×10^{-6} ohm, and

3) Verifying that the average electrolyte temperature of six connected cells is above 60°F.

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

1) The cells, cell plates and battery racks show no visual indication of physical damage or abnormal deterioration,

2) The battery to battery and terminal connections are clean, tight and coated with anticorrosion material, and

ALTERNATE
PROPOSAL

SURVEILLANCE REQUIREMENTS (Continued)

h. At least once per 10 years by:

1) Draining each 7-day fuel storage tank, removing the accumulated sediment and cleaning the tank using a sodium hypochlorite solution, and

2) Performing a pressure test of those portions of the diesel fuel oil system designed to Section III, subsection ND of the ASME Code* at a test pressure equal to 110% of the system design pressure.

4.8.1.1.3 The 125-volt D.C. distribution panel, 125-volt D.C. battery bank and associated charger for each diesel generator shall be demonstrated OPERABLE:

a. At least once per 7 days by verifying:

1) Correct breaker alignment, indicated power availability and voltage on the distribution panels greater than or equal to 118 volts,

2) That each battery bank and charger meet the Category A limits in Table 4.8-2 of Specification 4.8.2.1, and

3) That the total battery terminal voltage is greater than or equal to 125 volts on float charge.

b. At least once per 92 days and within 7 days after a battery discharge with a battery terminal voltage below 100 volts or a battery overcharge with a battery terminal voltage above 136 volts by:

1) Verifying that the parameters in Table 4.8-2 of Specification 4.8.2.1 meet the Category B limits,

2) Verifying there is no visible corrosion at either terminals or connectors, or the cell to terminal connection resistance of these items is less than 150×10^{-6} ohm, and

3) Verifying that the average electrolyte temperature of six connected cells is above 60°F.

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

1) The cells, cell plates and battery racks show no visual indication of physical damage or abnormal deterioration,

2) The battery to battery and terminal connections are clean, tight and coated with anticorrosion material, and

*Except those portions exempted by ASME Code Case N-240.

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REGULATORY GUIDE

OFFICE OF NUCLEAR REGULATORY RESEARCH

CASE

N-240

REGULATORY GUIDE 1.84

CASES OF ASME BOILER AND PRESSURE VESSEL CODE
CODE CASE ACCEPTABILITY
ASME SECTION III DIVISION 1

Approval Date: January 21, 1982

See Numeric Index for expiration and any reaffirmation dates.

A. INTRODUCTION

Case N-240
Hydrostatic Testing of Open Ended Piping
Section III, Division 1

Inquiry: For Section III, Division 1, Class 2 and 3 construction, may piping whose only function is to transport fluids to and from spray ponds, lakes, reservoirs, or tanks which are open to the atmosphere be exempted from hydrostatic testing?

Reply: Section III, Division 1 construction it is not required to hydrostatically test piping whose only function is to transport fluids to and from spray ponds, lakes, reservoirs or tanks open to the atmosphere provided that:

(1) the piping is constructed to all other requirements of this Section, and

(2) the following piping is hydrostatically tested in accordance with the requirements of this Section;

(a) piping upstream from the first isolation valve preceding the pipe discharge to the spray pond, lake, reservoir or tank, and

(b) piping downstream of the intake pump discharge isolation valve.

B. DISCUSSION

U.S. NUCLEAR REGULATORY COMMISSION

Revision 22
July 1984

REGULATORY GUIDE

OFFICE OF NUCLEAR REGULATORY RESEARCH

REGULATORY GUIDE 1.84

DESIGN AND FABRICATION CODE CASE ACCEPTABILITY ASME SECTION III DIVISION 1

A. INTRODUCTION

Section 50.55a, "Codes and Standards," of 10 CFR Part 50, "Domestic Licensing of Production and Utilization Facilities," requires, in part, that components of the reactor coolant pressure boundary be designed, fabricated, erected, and tested in accordance with the requirements for Class 1 components of Section III, "Nuclear Power Plant Components,"[1] of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code or equivalent quality standards. Footnote 6 to §50.55a states that the use of specific Code Cases may be authorized by the Commission upon request pursuant to §50.55a(a)(2)(ii), which requires that proposed alternatives to the described requirements or portions thereof provide an acceptable level of quality and safety.

General Design Criterion 1, "Quality Standards and Records," of Appendix A, "General Design Criteria for Nuclear Power Plants," to 10 CFR Part 50 requires, in part, that structures, systems, and components important to safety be designed, fabricated, erected, and tested to quality standards commensurate with the importance of the safety function to be performed. Where generally recognized codes and standards are used, Criterion 1 requires that they be identified and evaluated to determine their applicability, adequacy, and sufficiency and be supplemented or modified as necessary to ensure a quality product in keeping with the required safety function.

Criterion 30, "Quality of Reactor Coolant Pressure Boundary," of the same appendix requires, in part, that components that are part of the reactor coolant pressure boundary be designed, fabricated, erected, and tested to the highest quality standards practical.

Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants," to 10 CFR Part 50 requires, in part, that measures be established for the control of special processing of materials and that proper testing be performed.

This regulatory guide lists those Section III ASME Code Cases oriented to design and fabrication that are generally acceptable to the NRC staff for implementation in the licensing of light-water-cooled nuclear power plants.

Any guidance in this document related to information collection activities has been cleared under OMB Clearance No. 3150-0011.

B. DISCUSSION

The ASME Boiler and Pressure Vessel Committee publishes a document entitled "Code Cases."[1] Generally, the individual Code Cases that make up this document explain the intent of Code rules or provide for alternative requirements under special circumstances.

Most Code Cases are eventually superseded by revision to the Code and then are annulled by action of the ASME Council. In such cases, the intent of the annulled Code Case becomes part of the revised Code, and therefore continued use of the Code Case intent is sanctioned under the rules of the Code. In other cases, the Code Case is annulled because it is no longer acceptable or there is no further requirement for it. A Code Case that was approved for a particular situation and not for a generic application should be used only for construction of the approved situation because annulment of such a Code Case could result in construction that would not meet Code requirements.

The Code Cases listed in this guide are limited to those cases applicable to Section III that are oriented toward design and fabrication.

All published Code Cases in the area of design and fabrication that are applicable to Section III of the Code

[1] Copies may be obtained from the American Society of Mechanical Engineers, United Engineering Center, 345 East 47th Street, New York, New York 10017.

b. Fabrication-oriented Code Cases:

(1) Code Cases related to welding and brazing:

1609-1 (N-55)	03-01-76 08-28-78 07-13-81	Inertia and Continuous Drive Friction Welding, Section I, III, IV, VIII, Division 1 and 2, and IX
1791 (N-154)	03-17-80[5] 09-09-82	Projection Resistance Welding of Valve Seats, Section III, Division 1, Class 1, 2 and 3 Valves
N-217-1	01-07-80 09-07-82	Postweld Heat Treatment of Weld Deposit Cladding on Classes 1, 2, 3, MC, and CS Items, Section III, Division 1
N-229	01-08-79 01-21-82	Alternate Rules for Fabrication Welding SB-148 Alloy CDA 954 for Section III, Division 1, Class 3 Construction
N-233	01-08-79 01-21-82	Alternate Rules for PWHT of P-No. 6, Group 4 Material for Section III, Division 1, Class 1, 2, or 3 Construction
N-260	01-07-80 05-25-83	Weld Repair of SA-182 Type 316 Forgings, Section III, Division 1, Classes 1, 2, 3, and MC
N-262	01-07-80 09-07-82	Electric Resistance Spot Welding for Structural Use in Component Supports, Section III, Division 1
N-271	03-17-80	Simplified Method for Analyzing Flat Face Flanges with Metal to Metal Contact Outside the Bolt Circle for Section III, Class 2, 3, and MC Construction
N-276	03-17-80 02-14-83	Welding of SA-358 Pipe, Section III, Division 1
N-302	03-16-81	Tack Welding, Section III, Division 1 Construction
N-304	06-11-81	Use of 20Cr-25Ni-6Mo (Alloy UNS NO8366) Welded Tubes for Section III, Division 1, Class 2 and 3 Construction
N-315	02-14-83	Repair of Bellows, Section III, Division 1

Code Case N-315 is acceptable subject to the following conditions in addition to those conditions specified in the Code Case: Prior to implementation of the Code Case, the applicant should present a description of the repair and a justification why the bellows should be repaired rather than replaced. Following receipt of approval for the repair, but prior to making the repair, the applicant should present the results of the qualification on the full-scale facsimile bellows, including the design requirements, to ensure that the repair meets the requirements of the design specification.

N-316	12-11-81	Alternate Rules for Fillet Weld Dimensions for Socket Welded Fittings, Section III, Division 1, Class 1, 2, and 3
N-320	07-13-81	Alternate PWHT for SA-487, Grade CA6NM, Section III, Division 1
N-328	12-11-81	Thermit Brazing or Welding of Nonstructural Attachments, Section III, Division 1
N-345-1	12-13-82	Attachment of AMS 5382 Alloy 31 Seat Rings by Friction Welding, Section III, Division 1, Classes 1, 2, and 3
N-346	06-17-82	Explosive Welding, Section III, Division 1
N-347	12-13-82	Continuous Electric Resistance Seam Welding of P-No. 8 Materials for Component Supports, Section III, Division 1
N-357	12-13-82	Certification of Material for Component Supports, Section III, Division 1, Subsection NF
N-359	12-13-82	Weld Connection for Coaxial Cylinders, Section III, Division 1, Class 1
N-377	04-04-83	Effective Throat Thickness of Partial Penetration Groove Welds, Section III, Division 1, Classes 1, 2, and 3

(2) Other Code Cases related to fabrication:

N-215	05-15-78	Integrally Finned Titanium Tubes, Section III, Division 1, Class 3 Construction
N-237-2	05-25-83	Hydrostatic Testing of Internal Piping, Section III, Division 1, ~~Classes 2 and 3~~
N-240	03-19-79 01-21-82	Hydrostatic Testing of Open Ended Piping, Section III, Division 1
~~N-241~~	~~07-09-79~~ 01-21-82	~~Hydrostatic Testing of Piping, Sec-~~ tion III, Division 1
N-339	06-17-82	Examination of Ends of Fillet Welds, Section III, Division 1, Classes 1, 2, and MC
N-349	07-16-82	Pressure Testing Piping Systems, Section III, Division 1, Classes 2 and 3
N-362-1	05-25-83	Pressure Testing of Containment Items, Section III, Division 1, Classes 1, 2, and MC
N-368	07-06-83	Pressure Testing of Pump Discharge, Section III, Division 1, Classes 2 and 3

Code Case N-368 is acceptable subject to the following condition in addition to those conditions specified in the Code Case: Applicants utilizing this Code Case should provide information to demonstrate that the length of discharge piping is reasonably short.

[5] The Code Case was annulled on January 14, 1980 (ASME mandatory annulment date). It was reinstated on March 17, 1980. Because of the circumstances and because there were no changes in the Code Case, the NRC considers that this Case was in effect during the period of 1/14/80 through 3/17/80.

The deletion of the limit of 10 percent to the remedial testing part of surveillance requirement 4.8.3.3.a is unduly restrictive. Additional representative sampling has always been part of NRC's remedial testing policy. This is true for ice weighing, snubber testing, and other testing for electrical devices. Molded-case circuit breakers should not be singled out for more restrictive testing.

As documented in the letter from L. M. Mills to E. Adensam dated May 14, 1984 (A27 840514 005), "molded-case circuit breakers have an excellent record of reliability" (NEMA Standard AB2-1980). There is no reason to suspect that the failure of a single device is anything other than a random failure. The recent change to this surveillance requirement seems, however, to suggest that molded-case circuit breakers are more prone to failure than experience would lead one to believe.

TVA requests that the 10 percent limit on remedial testing be reinstated. The molded-case circuit breakers are highly reliable. They do not warrant this more restrictive response. The removal of the 10 percent limit cause two problems for TVA. First, the additional cost increased because of a random failure increases ninefold with the current surveillance requirement. This is an economic penalty not warranted by the excellent performance of molded-case circuit breakers. Second, a random failure increases the testing manpower requirement ninefold.

This makes outage planning, scheduling, and execution more difficult because workloads can increase significantly.

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FINAL DRAFT

ISOLATION DEVICES

LIMITING CONDITION FOR OPERATION

3.8.3.3 All circuit breakers actuated by fault currents that are used as isolation devices protecting 1E busses from non-qualified loads shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

With one or more of the above required circuit breakers inoperable:

a. Restore the inoperable circuit breaker(s) to OPERABLE status within 8 hours, or

b. Trip the inoperable circuit breaker(s), rackout the circuit breaker(s) within 8 hours and verify the circuit breaker(s) to be racked out at least once per 7 days thereafter; the provisions of Specification 3.0.4 are not applicable to racked-out circuit breakers, or

c. Be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.8.3.3 Each of the above required circuit breakers shall be demonstrated OPERABLE:

a. At least once per 18 months by selecting and performing a functional test on a representative sample of at least 10% of each type of molded-case circuit breakers. The molded-case circuit breakers selected for functional testing shall be selected on a rotating basis. The functional test (in accordance with NEMA Standard AB2-1980) shall consist of manually tripping (exercising) the circuit breaker twice and observing that the mechanical linkage is not binding or excessively loose, and inspecting all connections to the molded-case circuit breaker for tightness and signs of overheating. For each device found inoperable during the manual operating portion of the functional test of the selected molded-case circuit breakers, ~~the~~ ~~defective type molded-case circuit breakers shall be functionally tested until all devices of that type have been functionally tested;~~ an additional representative sample of at least 10% of the defective type molded-case circuit breakers shall also be functionally tested until no more defective molded-case circuit breakers are found or all devices of that type have been functionally tested;

OCT 26 1984

TVA submitted the change in fuse testing from functional to visual by letter dated September 15, 1982 (A27 820915 002). A detailed justification for this change was included with the request. The change was approved by NRC shortly thereafter. The letter from D. S. Karmer to E. Adensam dated July 27, 1983 (A27 830727 008), resubmitted those changes from the September 15, 1982, letter that were not approved. The fuse testing change was not included in that submittal.

As noted in the justification, TVA uses inline cable protecting fuses in many cases. The resistance test is destructive for these fuses. It is wasteful and unnecessary because the fuses are highly reliable and do not require this kind of testing. The manufacturer has attested to this fact. Nondestructive resistance measurement testing could only be done after the installation of a costly modification. Preliminary estimates range from $500,000 to $1,000,000 for the necessary modifications. In addition, the manufacturer does not publish baseline resistance valves. They do not because the valves are subject to change for a type of fuse as manufacturing techniques and materials change. The quality assurance problems stemning from receipt and control of fuses and resistance valves are difficult to imagine. This information has been presented to the NRC reviewers as part of a technical specification change for Sequoyah Nuclear Plant.

For these reasons TVA requests that the technical specifications be changed to require a visual inspection program in lieu of resistance measurements.

DE05:CHNG6.GT

WATTS BAR NUCLEAR PLANT
TECHNICAL SPECIFICATIONS INPUT

Open Item No. 193
T.S. Page 3/4 8-19

<u>Fuse Testing Surveillance Requirement</u> - Current standard technical specifications require that at least 10% of the fuses used for containment penetration conductor overcurrent protection be tested every 18 months. We believe that this requirement is costly, unnecessary, and possibly detrimental to safety. The bases for these positions are discussed below.

The requirement is costly because manpower and material is wasted. The vast majority of the fuses used for this type of protection are inline fuses. They cannot be tested (resistance measurement) without removing them from the circuit and/or destroying the heat shrink insulator material. They are designed to be installed permanently. Gould, Inc., a fuse manufacturer, has indicated that 'cable protector fuses are extra heavy so (they) are the least susceptible to deterioration of all types.' They also indicate that they 'have not seen a cable protecting fuse fail for any reason in nearly thirty years of sales.' The waste of manpower and materials are not warranted because no added protection is added by periodic testing of fuses.

The requirement is unnecessary because any fuse deterioration makes a fuse more protective; Gould, Inc. states that under 'no condition can a current limiting fuse ever become less protective over life.' As indicated, fuses can only become more protective with life; therefore, the testing of fuse resistance is wasteful and unnecessary.

The requirement can possible be detrimental to safety. Unnecessary removal of fuses from their holders on a regular basis can compromise the integrity of the contact points. Damaging the holder can lead to the unwanted de-energization of vital equipment. Obviously, this is undesirable and should be avoided.

For the reasons stated above, we believe fuse testing by resistance measurement is costly, unnecessary, and possibly detrimental to safety. Fuses do not deteriorate in an unsafe manner.

References: Letter from J. S. Wall (Gould, Inc.) ;to J. Honeycutt (TVA) dated February 24, 1982

FSAR page 8.1-9

Gould Inc., Electric Fuse Division
374 Merrimac Street Newburyport Massachusetts 01950
Telephone (617) 462-6662/462-3131/TWX 710-347-0204
Telex 094-7427

GOULD

L23 820305 621

ELECTRICAL EQUIP. GROUP
MAR 05 '82

	Note	Act'n	Reply
GRP			
PWR			
AUX	✓		
SYS			
SPEC			

①

JAT - This memo should help us eliminate the fuse testing requirement at SQNP. We are pursuing

Sur 3/10

xc: ARMS 3/5 mg

February 24, 1982

Mr. Jerry Honeycutt
TVA - Electrical Equip. Group
1330 Chestnut St., Towers #2
Chattanooga, TN 37401

Subject: Fuse Integrity

Dear Jerry:

To confirm our discussions concerning the integrity and life of fuses, we are pleased to present our thoughts.

The principal applications of fuses are in the protection of cables in branch circuits and in equipment protection. In either application the protective ability of a fuse will remain constant as long as the operating ambient temperature does not increase and threatens the temperature rating of the fuse body material. High temperature, current surges or unusual cycling conditions can reduce the life of a fuse but this simply means it becomes more protective. Under no condition can a current limiting fuse ever become less protective over life. End of life for a fuse is always the open position.

The best way to determine the condition of a fuse is to measure its resistance. At Gould Shawmut, we test to verify that production fuses lie within a narrow band of resistances established for each ampere rating. These resistances are not published because construction changes can occur at any time as designs change or materials are improved. A fuse resistance measured at 25 °C will not change over the life of that fuse regardless of length of service. Fuse resistance will only begin to change (increase) when unusual loading, cycling or indeed a short circuit occurs. Until that time, there is no need to replace a fuse because it will not deteriorate in any way.

Because fuses do not deteriorate, we see no need to periodically change them out. If there is indeed a requirement to replace all fuses, then we would urge that the time period be not less than 20 years. We feel that unnecessary removal of fuses from their holders on a regular basis can compromise the integrity of the contact points. Occasional random fuse removal would be acceptable for periodic checks.

Under no circumstances can cable protecting fuses be removed from cables without physically destroying them because of the crimped joint. Of all fuses, cable protector fuses are extra heavy so are the least susceptible to deterioration of

GOULD

all types. They are designed for cable isolation only under extreme overcurrent condition. Utilities typically install them permanently with no intention of ever disturbing them. We have not seen a cable protecting fuse fail for any reason in nearly thirty years of sales.

We trust that these thoughts will help clarify our position. Please let us know when we can help further.

Sincerely yours,

John S. Wall

John S. Wall
Product Application Mgr.

JSW:bm

CC: [redacted]

JUSTIFICATION FOR MODIFICATION OF SURVEILLANCE REQUIREMENTS
FOR TESTING OF CONTAINMENT PROTECTIVE FUSES

Technical Specification 4.8.3.1.a.3 requires that at least 10 percent of the fuses used for containment penetration conductor overcurrent protection be tested every 18 months. TVA believes that this requirement is costly and unnecessary because it does not enhance the safety or reliability of the plant. In fact, the testing may be detrimental to safety because excessive removal and insertion of fuses in the fuse holders may damage the contact points and the removal and replacement of in-line current limiters may compromise cable integrity. Both of these conditions can lead to an unwanted deenergization of equipment.

Gould Shawmut, a major fuse manufacturer, has provided TVA information to the effect that "(U)nder no condition can a current limiting fuse ever become less protective over life." It indicates that high temperatures, current surges, or unusual cycling conditions can reduce the life of a fuse "but this simply means it becomes more protective. Fuse resistance will only begin to change increase when unusual loading, cycling or indeed a short circuit occurs." In addition it provided the following information on cable protecting fuses.

> Under no circumstances can cable protecting fuses be removed from cables without physically destroying them because of the crimped joint. Of all fuses, cable protector fuses are extra heavy so are (sic) the least susceptible to deterioration of all types. They are designed for cable isolation only under extreme overcurrent condition (sic). Utilities typically install them permanently with no intention of ever disturbing them. We have not seen a cable protecting fuse fail for any reason in nearly thirty years of sales.

In addition to the crimped joints, these fuses are wrapped with heat shrink insulation material which must be cut off in order to remove the fuse. The fuse and wrap are destroyed for each test.

Gould Shawmut uses resistance measurements for production quality control. However, these "resistances are not published because construction changes can occur at any time as designs change or materials are improved." The fuse resistance is a good measure of a fuse's rating, but it is not necessary to periodically remeasure the resistance because the fuse degradation mode does not decrease resistance.

In summary, TVA believes that a fuse inspection and maintenance program to verify that the proper size and type of fuse is installed, the fuse shows no signs of deterioration, and the fuse connections are tight and clean would ensure that the necessary level of containment penetration conductor overcurrent protection is maintained. The present technical specification requires testing that is unnecessary and costly because fuse resistance does not decrease under degrading conditions, it only will increase (and become more protective). In the case of large cable protecting fuses, the testing is destructive.

TVA met with NRC's Instrumentation and Controls System Branch on January 26, 1980 to discuss the electrical system technical specifications for Sequoyah unit 1. At that time, TVA stated its objections to the technical specification requirement to measure fuse resistances. However, the staff indicated that TVA did not have enough evidence to support the request. We trust that the experience of Gould Shawmut is sufficient evidence to support our claim that fuse resistance is unnecessary to ensure that containment penetrations are protected from conductor overcurrents.

TVA has considered the effect of oxidation at the point of contact between the fuse and fuse clip. We have determined that any oxidation at this point will not be detrimental to the overall safety function performed by the containment penetration protection fuses.

TVA plans to inspect for visible contact oxidation or evidence of damage or degradation as part of the periodic visual inspection. Any oxidation that may occur between inspections would raise the resistance at the point of contact. The increased contact resistance could cause local heating of the fuse. However, any heating that could, over an extended time period, lead to circuit failure would also lead to visible heat marks. The heat marks would be detected during the visual inspection. It must be noted that any heat related damage does not reduce the penetration protection provided by the fuse. Any oxidation or increase in temperature will make the circuit more restrictive to current flow due to increased resistance. The fuse will still provide the same level of protection because in a constant voltage circuit, current must decrease if resistance increases. This phenomena is explained by Ohm's law. If there is any increase in loading, the fuse will still blow at its rated current, thereby protecting the penetration. In the limiting case, if contact resistance increased to the point of keeping the current below the rated value of the fuse, the safety function would still be accomplished: The current through the penetration would still be limited. The worst case of oxidation of the contact point would be noted by an open circuit. All of the equipment is either in regular service during power operation or it is periodically energized as part of the equipment functional tests, at which time any operational problems would be noted.

c) For each circuit breaker found inoperable during these functional tests, an additional circuit breaker of the inoperable type shall also be functionally tested until no more failures are found or all circuit breakers of that type have been functionally tested.

2) By selecting and functionally testing a representative sample of at least 10% of each type of electrically-operated circuit breakers. Electrically-operated circuit breakers selected for functional testing shall be selected on a rotating basis. The functional test shall consist of injecting a current input at the specified Setpoint to each selected electrically-operated circuit breaker or trip device and verifying that each electrically-operated circuit breaker or trip device functions as designed. Circuit breakers found inoperable during functional testing shall be restored to OPERABLE status prior to resuming operation. For each device found inoperable during these functional tests, an additional representative sample of at least 10% of the defective type electrically-operated circuit breakers shall also be functionally tested until no more failures are found or all electrically-operated circuit breakers of that type have been functionally tested; and

3) By selecting and ~~functionally testing~~ visually inspecting a representative sample of each type of fuse on a rotating basis. Each representative ~~sample of~~ fuses shall include at least 10% of all fuses of that type. The ~~functional test~~ visual inspection shall ~~consist of a non-destructive measurement test which demonstrates that the fuse meets its manufacturer's design criteria~~. Fuses found to be inoperable during these ~~functional tests~~ visual inspections shall be repaired or replaced with OPERABLE fuses prior to resuming operation. For each fuse found inoperable during these ~~functional tests~~, an additional representative sample of at least 10% of all fuses of that type ~~shall be functionally tested~~ until no more failures are found or all fuses of that type have been ~~functional tested.~~ Visually inspected

b. At least once per 60 months by subjecting each circuit breaker to an inspection and preventive maintenance in accordance with procedures prepared in conjunction with its manufacturer's recommendations.

ensure that the fuse shows no sign of deterioration or degradation and, for clip type fuses, that the proper size and type of fuse is installed and that the connections are clean, tight, and free of visible oxidation.

ELECTRICAL POWER SYSTEMS - ISOLATION DEVICES - SPECIFICATION 4.8.3.3 - (PAGE 3/4 8-18) AND SPECIFICATIONS 3.8.4.1 AND 4.8.4.1 - ELECTRICAL EQUIPMENT PROTECTIVE DEVICES - (PAGES 3/4 8-19 AND 3/4 8-20)

TVA also proposed that Table 3.8-1 'Containment Penetration Conductor Overcurrent Protection Devices' be deleted and that this information be maintained in plant procedures. This is consistent with the approach recently taken by the NRC staff on the snubber technicial specifications.

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3/4.8.4 ELECTRICAL EQUIPMENT PROTECTIVE DEVICES

CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

LIMITING CONDITION FOR OPERATION

3.8.4.1 All containment penetration conductor overcurrent protective devices ~~given in Table 3.8-1~~ shall be OPERABLE.

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

ACTION:

With one or more of the above required containment penetration conductor overcurrent protective device(s) inoperable:

a. Restore the protective device(s) to OPERABLE status or deenergize the circuit(s) by tripping the associated backup circuit breaker or racking out or removing the inoperable circuit breaker within 72 hours, declare the affected system or component inoperable, and verify the backup circuit breaker to be tripped or the inoperable circuit breaker racked out, or removed, at least once per 7 days thereafter; the provisions of Specification 3.0.4 are not applicable to overcurrent devices in circuits which have their backup circuit breakers tripped, their inoperable circuit breakers racked out, or removed, or

b. Be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.8.4.1 All containment penetration conductor overcurrent protective devices ~~given in Table 3.8-1~~ shall be demonstrated OPERABLE:

a. At least once per 18 months:

1) For at least one 6900-volt reactor coolant pump circuit such that all reactor coolant pump circuits are demonstrated OPERABLE at least once per 72 months by performance of the following:

a) A CHANNEL CALIBRATION of the associated protective relays,

b) An integrated system functional test which includes simulated automatic actuation of the system and verifying that each relay and associated circuit breakers and control circuits function as designed ~~and as specified in Table 3.8-1~~, and

TABLE 3.8-1

CONTAINMENT PENETRATION CONDUCTOR OVERCURRENT PROTECTIVE DEVICES

PRIMARY DEVICE NUMBER	BACKUP DEVICE NUMBER	LOCATION OF DEVICES	SYSTEM POWERED
1. 6.9kV RCP Boards			
52-202 -2/1A	52-2112	6.9kV RCP BD 1A	REAC Coolant Pump 1
52-202 -2/1B	52-2114	6.9kV RCP BD 1B	REAC Coolant Pump 2
52-202 -2/1C	52-2122	6.9kV RCP BD 1C	REAC Coolant Pump 3
52-2[illegible]2 -3/1[illegible]	52-2124	6.9kV RCP BD 1C	REAC Coolant Pump 4
2 480V Boards			
52-212 -7B/A1	FU-212 -A17/13	Shutdown BD 1A1-A	CRD MECH CLR FAN 1A-A/1
52-212 -7D/A1	FU-212 -A17/13	Shutdown BD 1A1-A	CRD MECH CLR FAN 1A-A/2
52-212 -7C/A1	FU-212 -A17/23	Shutdown BD 1A1-A	REAC LWR COMP CLR FAN 1A-A
52-212 -10C/A1	FU-212 -A110/23	Shutdown BD 1A1-A	CNTMT AIR RTN FAN 1A-A
52-212 -7A/A2	FU-212 -A27/3	Shutdown BD 1A2-A	CRD MECH CLR C-A Supply
52-212 -7D/A2	FU-212 -A21/33	Shutdown BD 1A2-A	REAC LWR COMPT CLR FAN C-A
52-212 -[illegible]A/A2	FU-212 -A28/3	Shutdown BD 1A2-A	CRD MECH CLR FAN 1C-A/2
52-212 -7C/B1	FU-212 -B17/23	Shutdown BD 1B1-B	CRD MECH CLR FAN 1B-B/1

Delete Entire TABLE

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Containment Purge System - Specification 3.9.13

The system flow rates have been revised to reflect the actual flow rates measured during preoperational testing. The A train flow rate is 10,300 cfm and the train B flow rate is 12,700 cfm.

3/4.9.13 REACTOR BUILDING PURGE VENTILATION SYSTEM

LIMITING CONDITION FOR OPERATION

3.9.13 The Reactor Building Purge Ventilation Systems shall be OPERABLE.

APPLICABILITY: During CORE ALTERATIONS or movement of irradiated fuel within the containment.

ACTION:

a. With one Reactor Building Purge Ventilation System inoperable, CORE ALTERATIONS or movement of irradiated fuel within the containment may proceed provided the OPERABLE Reactor Building Purge Ventilation System is capable of being powered from an OPERABLE emergency power source and is in operation and discharging through at least one train of HEPA filters and charcoal adsorbers.

b. With no Reactor Building Purge Ventilation System OPERABLE, suspend all operations involving CORE ALTERATIONS or movement of irradiated fuel within the containment until at least one Reactor Building Purge Ventilation System is restored to OPERABLE status.

c. The provisions of Specification 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.9.13 The above required Reactor Building Purge Ventilation Systems 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 system operates for at least 15 minutes;

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 system statisfies the in-place penetration and bypass leakage acceptance criteria of less than 1% and uses the test procedure guidance of Regulatory Positions C.5.a, C.5.c, and C.5.d of Regulatory Guide 1.52, Revision 2, March 1978, and the system flow rate is ~~14,000 cfm~~ rated flow ± 10% (train A rated flow is 10,300 cfm and train B rated flow is 12,700 cfm).

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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 10%; and

3) Verifying a system flow rate of ~~14,000 cfm~~ rated flow ± 10% (train A rated flow is 10,300 cfm and train B rated flow is 12,700 cfm) during system operation when tested in accordance with ANSI N510-1975.

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 10%;

d. At least once per 18 months by:

1) Verifying that the pressure drop across the combined HEPA filters and charcoal adsorber banks is less than 6 inches Water Gauge while operating the system at a flow rate of ~~14,000 cfm~~ rated flow ± 10% ~~, and~~ (train A rated flow is 10,300 cfm and train B rated flow is 12,700 cfm); and

Also insert below

2) Verifying that on a High Radiation test signal, the system isolates.

e. After each complete or partial replacement of a HEPA filter bank, by verifying that the cleanup system satisfies the in-place penetration and bypass leakage testing acceptance criteria of less than 1% in accordance with ANSI N510-1975 for a DOP test aerosol while operating the system at a flow rate of ~~14,000 cfm~~ rated flow ± 10% ~~, and~~

f. After each complete or partial replacement of a charcoal adsorber bank, by verifying that the cleanup system satisfies the in-place penetration and bypass leakage testing acceptance criteria of less than 1% in accordance with ANSI N510-1975 for a halogenated hydrocarbon refrigerant test gas while operating the system at a flow rate of ~~14,000 cfm~~ rated flow ± 10%.

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Pages 3/411-5 and 3/411-13

The secondary coolant sample acceptance criteria should be changed from $1x10^{-7}$ to $1x10^{-6}$. On October 2, 1984, TVA discussed this item with the NRC reviewer by telephone. TVA explained that given the geometry, background, count time, and sampling equipment 10^{-7} is a goal that cannot be achieved. An acceptance criteria of $1x10^{-7}$ cannot be reliably measured. This would have the effect of negating the purpose of footnote (6) to Table 4.11-1 by requiring continuous sampling of the secondary system because the acceptance criteria cannot be measured. The NRC reviewer accepted these arguments and agreed to change the acceptance criteria to $1x10^{-6}$. This request serves to document that telephone call.

DE05:CHNG8.GT

TABLE 4.11-1 (Continued)

TABLE NOTATIONS (Continued)

(2) A batch release is the discharge of liquid wastes of a discrete volume. Prior to sampling for analyses, each batch shall be isolated, and then thoroughly mixed by a method described in the ODCM to assure representative sampling.

(3) The principal gamma emitters for which the LLD specification applies include the following radionuclides: Mn-54, Fe-59, Co-58, Co-60, Zn-65, Mo-99, Cs-134, Cs-137, Ce-141, and Ce-144. This list does not mean that only these nuclides are to be considered. Other gamma peaks that are identifiable, together with those of the above nuclides, shall also be analyzed and reported in the Semiannual Radioactive Effluent Release Report, pursuant to Specification 6.9.1.7, in the format outlined in Regulatory Guide 1.21, Appendix B, Revision 1, June 1974.

(4) A lab composite sample is one prepared by combining representative samples from each release into one well-mixed, homogenous sample. The volume of sample added to the composite from each release shall be proportional to the release volume.

(5) A continuous release is the discharge of liquid wastes of a nondiscrete volume, e.g., from a volume of a system that has an input flow during the continuous release.

(6) Not applicable when the most recent Secondary Coolant System specific activity sample and analysis program gross radioactivity determination is less than or equal to 1 x ~~[illegible]~~ μCi/gm and the discharge Radiation Monitor Setpoint is less than or equal to 1 x 10^{-6} μCi/ml above background.

10^{-6}

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TABLE 4.11-2 (Continued)

TABLE NOTATIONS (Continued)

(3) Sampling and analysis shall also be performed following shutdown, startup, or a THERMAL POWER change exceeding 15% of RATED THERMAL POWER within a 1-hour period unless (a) analysis shows that the DOSE EQUIVALENT I-131 concentration in the reactor coolant has not increased by more than a factor of 3, and (b) the lower containment noble gas activity monitor (RE-90-106 or RE-90-112) shows that the radioactivity has not increased by more than a factor of 3.

(4) Tritium grab samples shall be taken at least once per 24 hours when the refueling canal is flooded.

(5) Tritium grab samples shall be taken at least once per 7 days from the ventilation exhaust from the spent fuel pool area, whenever spent fuel is in the spent fuel pool.

(6) The ratio of the sample flow rate to the sampled stream flow rate shall be known for the time period covered by each dose or dose rate calculation made in accordance with Specifications 3.11.2.1, 3.11.2.2 and 3.11.2.3.

(7) Samples shall be changed at least once per 7 days and analyses shall be completed within 48 hours after changing, or after removal from sampler. Sampling shall also be performed at least once per 24 hours for at least 7 days following each shutdown, startup, or THERMAL POWER change exceeding 15% of RATED THERMAL POWER within a 1-hour period and analyses shall be completed within 48 hours of changing. When samples collected for 24 hours are analyzed, the corresponding LLDs may be increased by a factor of 10. This requirement does not apply if: (1) analysis shows that the DOSE EQUIVALENT I-131 concentration in the reactor coolant has not increased by more than a factor of 3; and (2) the noble gas monitor shows that the radioactivity has not increased by more than a factor of 3.

(8) During releases via this Exhaust System.

(9) In MODES 1, 2, 3, and 4, the upper and lower compartments of the containment shall be sampled prior to PURGING. Prior to breaking CONTAINMENT INTEGRITY in MODES 5 and 6, the upper and lower compartments of the containment shall be sampled. The incore instrument room purge sample shall be obtained at the shield building exhaust between 5 and 10 minutes following initiation of the incore instrument room purge.

(10) Prior to VENTING in MODES 1, 2, 3, and 4, the upper and lower compartments of the containment shall be sampled daily when VENTING is to occur on that day.

(11) Not applicable to the Shield Building Exhaust.

(12) Not applicable when the most recent Secondary Coolant System specific activity sample and analysis program gross radioactivity determination is less than or equal to 1 x ~~10~~ μCi/gm and the discharge Radiation Monitor Setpoint is less than or equal to 1 x 10^{-6} μCi/ml above background.

10^{-6}

3/4 11-17	Surveillance requirement 4.11.2.5 has been revised in format only. This change was made at the request of the operations staff to improve readability and to be structured to fit our surveillance instruction format. The intent has not changed.

RADIOACTIVE EFFLUENTS

FINAL DRAFT

EXPLOSIVE GAS MIXTURE

LIMITING CONDITION FOR OPERATION

3.11.2.5 The concentration of oxygen in the WASTE GAS HOLDUP SYSTEM shall be limited to less than or equal to 2% by volume whenever the hydrogen concentration exceeds 4% by volume.

APPLICABILITY: At all times.

ACTION:

a. With the concentration of oxygen in the WASTE GAS HOLDUP SYSTEM greater than 2% 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 and 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.11.2.5 The concentration of hydrogen and oxygen in any waste gas decay tank shall be determined ~~prior to the addition of waste gas to that tank or by continuously monitoring the waste gases transferred to that tank with the hydrogen and oxygen monitors required OPERABLE by Table 3.3-13 of Specification 3.3.3.10.~~

a. by sampling prior to transferring waste gases to that tank, or

b. by continuously monitoring the waste gases transferred to that tank with the Hydrogen and oxygen monitors required OPERABLE by Table 3.3-13 of Specification 3.3.3.10.

OCT 26 1984

Curie Limit for Gas Decay Tanks - Technical Specification 3.11.2.6

Specification 3.11.2.6 limits individual gas decay tanks to 67,000 curies as Xe-133 and requires an analysis be performed once per 24 hours to verify compliance. The basis for this specification is NUREG-0800, section 11.3, which requires that a failure of an active component in the waste gas system would not result in the total body exposure of an individual to exceed 0.5 rem at the site boundary. NRC Branch Technical Position ETSB 11-5 sets forth the minimum requirements to perform the calculations which result in the tank limit of 67,000 curies. One major assumption is that 1% of the operational equilibrium fission product inventory in the core has been released in the coolant. At the time this assumption becomes reality, the RCS activity would be in excess of that specified in LCO's 3.4.8.a and 3.4.8.b. Also prior to reaching the 67,000 curie per tank limit, the RCS fission gas activity would be in violation of LCO 3.4.8.b. Since the activities in the gas stream feeding the gas decay tanks is directly dependent on the RCS activities, sampling the tanks should not be required as long as LCO 3.4.8 is maintained.

The Sequoyah Nuclear Plant has been performing surveillance for specification 3.11.2.6 for approximately four years and have never exceeded 1% of the limit. To further emphasize the magnitude of 67,000 curies, NUREG/CR-2907 Volume 2, Table 2, shows from 1970 to 1981, only four times did nuclear plants release more than 67,000 curies <u>per year</u>, one of which was Three Mile Island 1. The estimated cost of satisfying this surveillance requirement is $18,000 per year and the analytical results are of <u>no</u> operational value.

Understanding the above information, one could draw the conclusion that plant productivity would be increased, without jeopardizing public safety if the surveillance requirements were revised such as:

"4.11.2.6 The quantity of radioactive material contained in each gas decay tank shall be maintained within the above limit by satisfying specification 3.4.8.b. Should the RCS activity exceed 10% of LCO 3.4.8.b, the activity of each gas decay tank being flled shall be determined within the above limit by laboratory analysis once per 24 hours."

RADIOACTIVE EFFLUENTS

GAS DECAY TANKS

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LIMITING CONDITION FOR OPERATION

3.11.2.6 The quantity of radioactivity contained in each gas decay tank shall be limited to less than or equal to 67,000 curies of noble gases considered as Xe-133 equivalent.

APPLICABILITY: At all times.

ACTION:

a. With the quantity of radioactive material in any gas decay tank exceeding the above limit, immediately suspend all additions of radioactive material to the tank and 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 6.9.1.7.

b. The provisions of Specifications 3.0.3 and 3.0.4 are not applicable.

SURVEILLANCE REQUIREMENTS

4.11.2.6 The quantity of radioactive material contained in each gas decay tank shall be determined to be within the above limit ~~at least once per 24 hours when radioactive materials are being added to the tank.~~ by satisfying Specification 3.4.8.b. Should the RCS activity exceed 10% of LCO 3.4.8.b, the activity of each gas decay tank being filled shall be determined within the above limit by laboratory analysis once per 24 hours.

B 3/4 4-15

Bases 3/4.4.9 should be revised as indicated to reflect the fact that a cold leg measured temperature is used to protect the reactor pressure from a predicted pressure-temperature condition.

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PRESSURE/TEMPERATURE LIMITS (Continued)

ramp. Furthermore, since the thermal stresses, at the outside are tensile and increase with increasing heatup rate, a lower bound curve cannot be defined. Rather, each heatup rate of interest must be analyzed on an individual basis.

Following the generation of pressure-temperature curves for both the steady-state and finite heatup rate situations, the final limit curves are produced as follows. A composite curve is constructed based on a point-by-point comparison of the steady-state and finite heatup rate data. At any given temperature, the allowable pressure is taken to be the lesser of the three values taken from the curves under consideration.

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.

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.

(heat input)

The OPERABILITY of two PORVs or an RCS vent opening of at least 3 square inches ensures that the RCS will be protected from pressure transients which could exceed the limits of Appendix G to 10 CFR Part 50 when one or more of the RCS cold legs are less than or equal to 310°F. Either PORV has adequate relieving capability to protect the RCS from overpressurization when the transient is limited to either: (1) the start of an idle reactor coolant pump 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 a HPSI pump and its injection into a water solid RCS.

(mass input)
Insert proposed paragraph

3/4.4.10 STRUCTURAL INTEGRITY

The inservice inspection and testing programs for ASME Code Class 1, 2 and 3 components ensure that the structural integrity and operational readiness of these components will be maintained at an acceptable level throughout the life of the plant. These programs are in accordance with Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda as required by 10 CFR 50.55a(g) except where specific written relief has been granted by the Commission pursuant to 10 CFR 50.55a(g)(6)(i).

Components of the Reactor Coolant System were designed to provide access to permit inservice inspections in accordance with Section XI of the ASME Boiler and Pressure Vessel Code, 1971 Edition and Addenda through Winter 1971.

Proposed Paragraph for page B 3/4 4-15

In developing the PORV setpoint for a given measured RTD temperature, account must be taken of the heat transport effect. If a heat input event were to occur, the cold leg temperature would rapidly rise to that corresponding to the steam generator, while the vessel would still be at the RCS temperature which existed prior to the transient. Therefore, the PORV setpoint must be defined so that it corresponds to the Appendix G limit at the vessel temperature, not the measured RTD temperature. It was assumed that the RTD was measuring a temperature 63°F higher than the vessel (50°F due to primary to secondary temperature difference plus 13°F instrument error). The actural PORV setpoints will be staggered and set below the nominal lift setting shown in Figure 3.4-4.

WBN Technical Specification Comments -
Nuclear Fuel Branch

1. Section 5.6.1.1, item a, should read ". . . a conservative allowance of 1.51 %ΔK for uncertainties . . . ," since K_{eff} is not 1.0 for the spent fuel pool. It now states ". . . 1.51%ΔK/K . . . ."

2. Section 5.6.3: The spent fuel storage pool, as it currently exists, is limited to no more than 1,294 fuel assemblies, since 18 cells were permanently plugged during the repair of the racks.

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5.6 FUEL STORAGE

CRITICALITY

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

a. A k_{eff} equivalent to less than or equal to 0.95 when flooded with unborated water, which includes a conservative allowance of 1.51% ~~Δk/k~~ ΔK for uncertainties as described in Section 4.3 of the FSAR, and

b. A nominal 10.75 inch center-to-center distance between fuel assemblies placed in the storage racks.

5.6.1.2 The k_{eff} for new fuel for the first core loading stored dry in the spent fuel storage racks shall not exceed 0.98 when aqueous foam moderation is assumed.

DRAINAGE

5.6.2 The spent fuel storage pool is designed and shall be maintained to prevent inadvertent draining of the pool below elevation 745 feet.

CAPACITY

5.6.3 The spent fuel storage pool is designed and shall be maintained with a storage capacity limited to no more than ~~1312~~ 1294 fuel assemblies.

5.7 COMPONENT CYCLIC OR TRANSIENT LIMIT

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

SECTION 6.0 - ADMINISTRATIVE CONTROLS - (PAGES 6-1 THRU 6-28)

TVA is in the process of a major reorganization whereby many of the tasks which are presently performed offsite will be transferred to onsite organizations. Section 6.0 'Administrative Controls' has been revised to reflect the new organizational and reporting chains.

Page 6-8 - There is no requirement to include administrative requirements for ISEG records. The Westinghouse Standard Technical Specifications Rev. 4 does not include such a requirement. Therefore, section 6.2.3.4 should be deleted from the Watts Bar Technical Specifications.

Incorporate additional changes as indicated.

DEC 1 1 1984

FINAL DRAFT

SECTION 6.0

ADMINISTRATIVE CONTROLS

DEC 1 1984

FINAL DRAFT

6.1 RESPONSIBILITY

6.1.1 The Plant Manager shall be responsible for overall unit operation and shall delegate in writing the succession to this responsibility during his absence.

6.1.2 ~~The Manager, Radiological Services~~ The Manager, Radiological Health, shall be responsible for implementing the Radiological Environmental Monitoring Program and for the development of and changes ~~to the~~ Offsite Dose Calculation Manual (ODCM) and for dose calculations and projections as described in the ODCM. These responsibilities include performance of Surveillance Requirements listed in Table 6.1-1.

6.1.3 The Shift Supervisor (or during his absence from the Control Room, a designated individual) shall be responsible for the Control Room command function. A management ~~directive~~ to this effect, signed by ~~the Site~~ Director, shall be reissued to ~~all~~ appropriate station personnel on an annual basis.

6.2 ORGANIZATION

OFFSITE

6.2.1 The offsite organization for unit management and technical support including radiological environmental monitoring and dose calculations shall be as shown on Figure 6.2-1.

UNIT STAFF

6.2.2 The unit organization shall be as shown on Figure 6.2-2 and:

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

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 Health Physics 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 a licensed Senior Operator Limited to Fuel Handling who has no other concurrent responsibilities during this operation;

e. A 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; and

* The Health Physics Technician 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.

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UNIT STAFF (Continued)

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, Health Physicists, Auxiliary Unit Operators, and key maintenance personnel.

Adequate shift coverage shall be maintained without routine heavy use of overtime. The objective shall be to have operating personnel work a normal 8-hour day, 40-hour week while the plant is operating. However, in the event that unforeseen problems require substantial amounts of overtime to be used, or during extended periods of shutdown for refueling, major maintenance or major plant modifications, on a temporary basis, the following guidelines shall be followed:

1) An individual should not be permitted to work more than 16 hours straight, excluding shift turnover time;

2) An individual should not be permitted to work more than 16 hours in any 24-hour period, nor more than 24 hours in any 48-hour period, nor more than 72 hours in any 7-day period, all excluding shift turnover time;

3) A break of at least 8 hours should be allowed between work periods, including shift turnover time; and

4) Except during extended shutdown periods, the use of overtime should be considered on an individual basis and not for the entire staff on a shift.

Any deviation from the above guidelines shall be authorized by the Plant Manager or his designee, or higher levels of management, in accordance with established procedures and with documentation of the basis for granting the deviation. Controls shall be included in the procedures such that individual overtime shall be reviewed monthly by the Plant Manager or his designee to assure that excessive hours have not been assigned. Routine deviation from the above guidelines is not authorized.

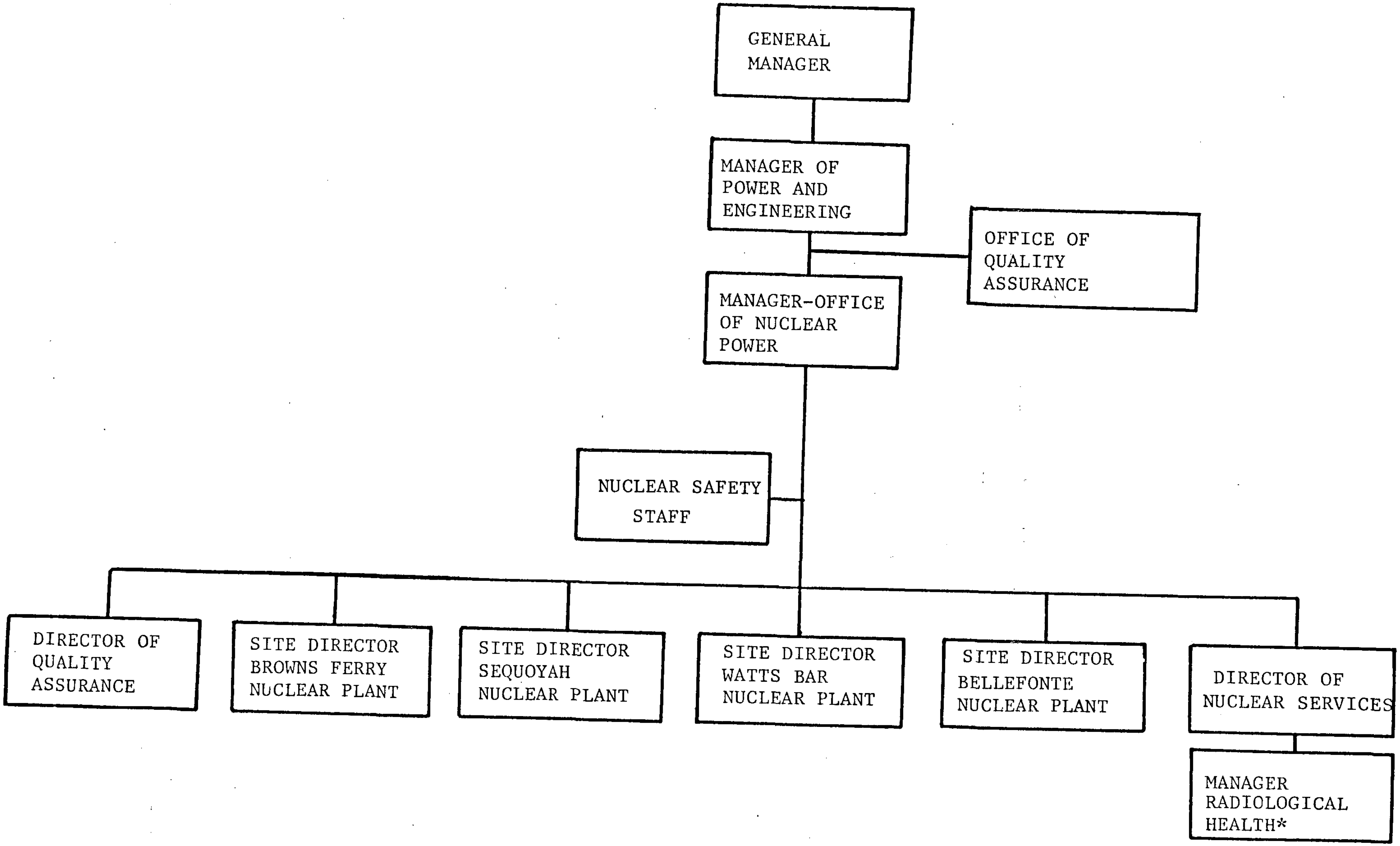

Figure 6.2-1
OFFSITE ORGANIZATION FOR FACILITY MANAGEMENT AND TECHNICAL SUPPORT

*Responsible for radiological environmental monitoring and dose calculations

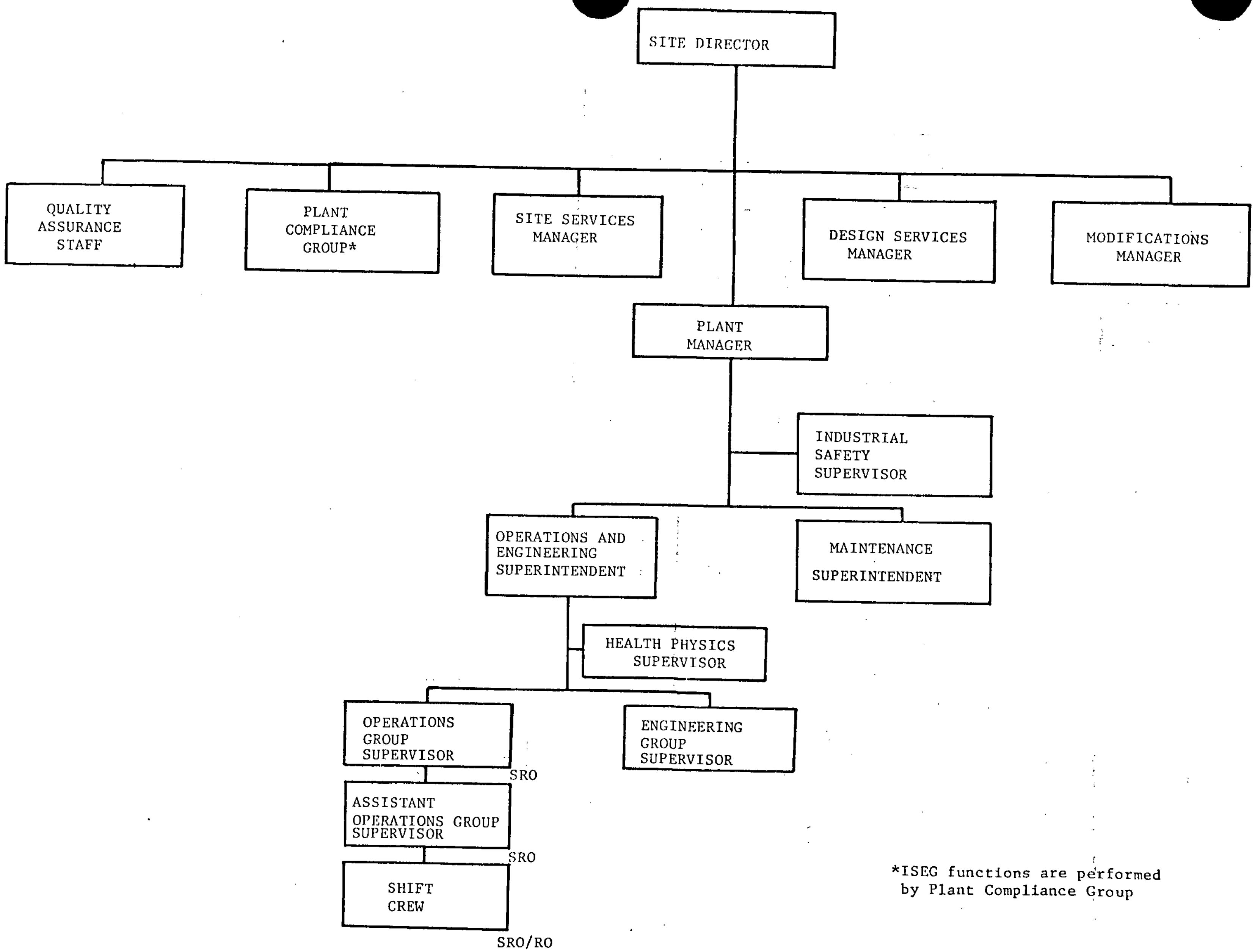

Figure 6.2-2
FACILITY ORGANIZATION

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TABLE 6.1-1

SURVEILLANCE REQUIREMENTS PERFORMED BY RADIOLOGICAL ~~SERVICES~~ HEALTH

1. Liquid Effluents - Specifications 4.11.1.2 (Partial) and 4.11.1.3.1. (partial)

2. Gaseous Effluents - Specifications 4.11.2.1.1 (partial) and 4.11.2.1.2 (partial).

3. Dose-Noble Gases - Specification 4.11.2.2. (partial)

4. Dose-Iodine-131 and 133, Tritium, and Radionuclides in Particulate Form - Specification 4.11.2.3. (partial)

5. Gaseous Radwaste Treatment System - Specification 4.11.2.4.1. (partial)

6. Total Dose - Specifications 4.11.4.1 and 4.11.4.2.

7. Monitoring Program - Specification 4.12.1.

8. Land Use Census - Specification 4.12.2.

9. Interlaboratory Comparison Program - Specification 4.12.3.

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TABLE 6.2-1

MINIMUM SHIFT CREW COMPOSITION

POSITION	NUMBER OF INDIVIDUALS REQUIRED TO FILL POSITION	
	MODE 1, 2, 3, or 4	MODE 5 or 6
SE	1	1
SRO	1	None
RO	2	1
AUO	2	1
STA	1*	None

SE - Shift Supervisor with a Senior Operator license on Unit 1
SRO - Individual with a Senior Operator license on Unit 1
RO - Individual with a Operator license on Unit 1
AUO - Auxiliary Unit Operator
STA - Shift Technical Advisor

The Shift Crew composition may be one less than the minimum requirements of Table 6.2-2 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 6.2-2. 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 or Operator license shall be designated to assume the Control Room command function.

*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.

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6.2.3 INDEPENDENT SAFETY ENGINEERING GROUP (ISEG)

FUNCTION

6.2.3.1 The ISEG shall function to examine plant operating characteristics, NRC issuances, industry advisories, Licensee Event Reports and other sources of plant design and operating experience information including plants of similar design, which may indicate areas for improving plant safety. The ISEG shall make detailed recommendations for revised procedures, equipment modifications, or other means of improving plant safety to the Site Director.

COMPOSITION

6.2.3.2 The ISEG shall be composed of at least three full-time engineers located onsite. Each shall have a bachelor's degree or equivalent in engineering or related science and at least 2 years professional level experience in ~~his~~ field.

RESPONSIBILITIES

6.2.3.3 The ISEG shall be responsible for maintaining surveillance of plant activities to provide independent verification* that these activities are performed correctly and that human errors are reduced as much as practical.

~~RECORDS~~

~~6.2.3.4 Records of activities performed by the ISEG shall be prepared, maintained, and periodically forwarded to the Manager, Maintenance and Engineering. A report summarizing ISEG review activities shall be prepared and provided each calendar month to the Site Director.~~

6.2.4 SHIFT TECHNICAL ADVISOR (STA)

6.2.4.1 The STA shall provide technical support to the Shift Supervisor in the areas of thermal hydraulics, reactor engineering and plant analysis with regard to the safe operation of the unit. The STA shall have a bachelor's degree or equivalent in a scientific or engineering discipline and shall have received specific training in the response and analysis of the unit for transients and accidents, and in unit design and layout including the capabilities of instrumentation and controls in the Control Room.

6.3 UNIT STAFF QUALIFICATIONS

6.3.1 Each member of the unit staff shall meet or exceed the minimum qualifications of ANSI N18.1-1971 for comparable positions, except for the Health Physics Supervisor, who shall meet or exceed the qualifications of Regulatory Guide 1.8, September 1975, for a Radiation Protection Manager. The licensed Operators and Senior Operators shall also meet or exceed the minimum qualifications of the supplemental requirements specified in Sections A and C of Enclosure 1 of the March 28, 1980 NRC letter to all licensees.

*Not responsible for sign-off function.

6.4 TRAINING

6.4.1 A retraining and replacement training program for the unit staff shall be maintained under the direction of the Operations and Engineering Superintendent and shall meet or exceed the requirements and recommendations of Section 5.5 of ANSI N18.1-1971 and Appendix A of 10 CFR Part 55 and the supplemental requirements specified in Sections A and C of Enclosure 1 of the March 28, 1980 NRC letter to all licensees, and shall include familiarization with relevant industry operational experience identified by the ISEG.

6.5 REVIEW AND AUDIT

6.5.0 The Manager, Office of Nuclear Power, is responsible for the safe operation of all TVA nuclear power plants. The functional organization for review and cognizance of audits is shown on Figure 6.2-1.

6.5.1 PLANT OPERATIONS REVIEW COMMITTEE (PORC)

FUNCTION

6.5.1.1 The PORC shall function to advise the Plant Superintendent on all matters related to nuclear safety.

COMPOSITION

6.5.1.2 The PORC shall be composed of at least a minimum of the following members, but in no case more than ten members:

Chairman:	Plant Manager or his Alternate
Member:	Operations Group Supervisor
Member:	Engineering Section Supervisor
Member:	Maintenance Supervisor (Electrical, Mechanical, or Instrumentation)
Member:	Health Physics Supervisor

ALTERNATES

6.5.1.3 All alternate members shall be appointed in writing by the PORC Chairman to serve on a temporary basis; however, no more than two alternates shall participate as voting members in PORC activities at any one time.

MEETING FREQUENCY

6.5.1.4 The PORC shall meet at least once per calendar month and as convened by the PORC Chairman or his designated alternate.

QUORUM

6.5.1.5 The quorum of the PORC necessary for the performance of the PORC responsibility and authority provisions of these Technical Specifications shall consist of the Chairman or his designated alternate and at least three members of the total membership, which must represent at least half of the total membership, including alternates.

RESPONSIBILITIES

6.5.1.6 The PORC shall be responsible for:

a. Review of: (1) all procedures required by Specification 6.8.1 and changes thereto, (2) all programs required by Specification 6.8.5, and changes thereto, and (3) any other proposed procedures or changes thereto as determined by the Plant Manager to affect nuclear safety;

b. Review of all proposed tests and experiments that affect nuclear safety;

c. Review of all proposed changes to Appendix "A" Technical Specifications;

d. Review of all proposed changes or modifications to unit systems or equipment that affect nuclear safety;

e. Investigation of all violations of the Technical Specifications including the preparation and forwarding of reports covering evaluation and recommendations to prevent recurrence to the Site Director, and to the Chief, Nuclear Safety Staff;

f. Review of all REPORTABLE EVENTS;

g. Review of unit operations to detect potential hazards to nuclear safety;

h. Performance of special reviews, investigations or analyses and reports thereon as requested by the Plant Manager or the Chief, Nuclear Safety Staff;

i. Review of the Plant Physical Security Plan and implementing procedures and shall submit recommended changes to the Chief, Nuclear Safety Staff;

j. Review of the Site Radiological Emergency Plan and implementing procedures and shall submit recommended changes to the Chief, Nuclear Safety Staff;

RESPONSIBILITIES (Continued)

k. Review of any accidental, unplanned or uncontrolled radioactive release including the preparation of reports covering evaluation, recommendations and disposition of the corrective action to prevent recurrence and the forwarding of these reports to the Site Director, and to the Chief, Nuclear Safety Staff;

l. Review of changes to the PROCESS CONTROL PROGRAM, the OFFSITE DOSE CALCULATION MANUAL, and the Radwaste Treatment Systems; and

m. Review of meeting minutes of Radiological Assessment Review Committee.

6.5.1.7 The PORC shall:

a. Recommend in writing to the Plant Manager approval or disapproval of items considered under Specification 6.5.1.6a. through d. above;

b. Render determinations in writing with regard to whether or not each item considered under Specification 6.5.1.6a. through e. above constitutes an unreviewed safety question; and

c. Provide written notification within 24 hours to the Site Director, and the Chief, Nuclear Safety Staff, of disagreement between the PORC and the Plant Manager; however, the Plant Manager shall have responsibility for resolution of such disagreements pursuant to Specification 6.1.1 above.

RECORDS

6.5.1.8 The PORC shall maintain written minutes of each PORC meeting that, at a minimum, document the results of all PORC activities performed under the responsibility and authority provisions of these technical specifications. Copies shall be provided to the Site Director, and the Chief, Nuclear Safety Staff.

6.5.2 NUCLEAR SAFETY STAFF (NSS)

FUNCTION

6.5.2.1 The NSS shall function to provide independent review and audit cognizance of designated activities in the areas of:

a. Nuclear power plant operations,
b. Nuclear engineering,
c. Chemistry and radiochemistry,
d. Metallurgy,
e. Instrumentation and control,
f. Radiological safety,
g. Mechanical and electrical engineering, and
h. Quality assurance practices.

~~The NSS shall report to and advise the Manager, Office of Nuclear Power on those areas of responsibility specified in Specifications 6.5.2.5 and 6.5.2.6.~~

RESPONSIBILITY

The NSS shall be responsible for the independent nuclear safety review program and cognizance of audits for all TVA nuclear plants, including Watts Bar.

MINIMUM REVIEW

6.5.2.5 A minimum of three reviewers shall review each of the subjects encompassed by sections 6.5.2.6 and 6.5.2.7.

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~~COMPOSITION~~

~~6.5.2.2 The NSS shall be composed of the Chief and TVA personnel designated as reviewers. A minimum of three designated TVA personnel shall review each designated activity.~~

QUALIFICATIONS

6.5.2.3 All NSS and other TVA personnel who have been designated as reviewers ~~The Chief, NSS, shall be appointed in writing by the Manager, Office of Nuclear Power, and~~ shall have an academic degree in engineering or a physical science field, or the equivalent; and in addition, shall have a minimum of 5 ~~6~~ years technical experience in one or more areas given in Specification 6.5.2.1. ~~Other TVA personnel designated as reviewers shall meet the same qualifications except the minimum technical experience may be 5 years.~~ The Chief, NSS shall meet the same qualifications as reviewers except that the minimum experience shall be six years.

CONSULTANTS

6.5.2.4 Consultants shall be utilized ~~as determined by the NSS Chief~~ to provide expert advice ~~to the NSS.~~ as determined by the Chief, NSS.

REVIEW

6.5.2.6 ~~5~~ The NSS shall review:

a. The safety evaluations for: (1) changes to procedures, equipment or systems, and (2) tests or experiments completed under the provision of Section 50.59, 10 CFR, to verify that such actions did not constitute an unreviewed safety question;

b. Proposed changes to procedures, equipment or systems which involve an unreviewed safety question as defined in Section 50.59, 10 CFR;

c. Proposed tests or experiments which involve an unreviewed safety question as defined in Section 50.59, 10 CFR;

d. Proposed changes to Technical Specifications or this Operating License;

e. Violations of Codes, regulations, orders, Technical Specifications, license requirements, or of internal procedures or instructions having nuclear safety significance;

f. Significant operating abnormalities or deviations from normal and expected performance of unit equipment that affect nuclear safety;

g. All REPORTABLE EVENTS;

h. All recognized indications of an unanticipated deficiency in some aspect of design or operation of structures, systems, or components that could affect nuclear safety; and

i. Reports and meeting minutes of the PORC and RARC.

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AUDIT~~S~~

6.5.2.~~8~~7 Audits of unit activities shall be performed under the cognizance of the NSS. These audits shall encompass:

a. The conformance of unit operation to provisions contained within the Technical Specifications and applicable license conditions at least once per 12 months;

b. The performance, training and qualifications of the entire unit staff at least once per 12 months;

c. The results of actions taken to correct deficiencies occurring in unit equipment, structures, systems or method of operation that affect nuclear safety at least once per 6 months;

d. The performance of activities required by the Operational Quality Assurance Program to meet the criteria of Appendix B, 10 CFR Part 50, at least once per 24 months;

e. The fire protection programmatic controls including the implementing procedures at least once per 24 months by qualified licensee QA personnel;

f. The fire protection equipment and program implementation at least once per 12 months utilizing either a qualified offsite licensee fire protection engineer or an outside independent fire protection consultant. An outside independent fire protection consultant shall be used at least every third year;

g. The Radiological Environmental Monitoring Program and the results thereof at least once per 12 months;

h. The OFFSITE DOSE CALCULATION MANUAL and implementing procedures at least once per 24 months;

i. The PROCESS CONTROL PROGRAM and implementing procedures for SOLIDIFICATION of radioactive wastes at least once per 24 months;

j. The performance of activities required by the Quality Assurance Program for effluent and environmental monitoring, at least once per 12 months; and

k. Any other area of unit operation considered appropriate by the NSS or the Manager, Office of Nuclear Power.

AUTHORITY

6.5.2.8 The NSS shall report to and advise the Manager, Office of Nuclear Power on those areas of responsibility specified in sections 6.5.2.~~6~~ and 6.5.2.7.

Insert

REPORTS

6.5.2.9 Reports of activities shall be prepared, approved, and distributed as indicated below:

a. Results of reviews and of cognizance of audits encompassed by Sections 6.5.2.6 and 6.5.2.7 above, shall be approved by the Chief, NSS, and forwarded to the Manager, Office of Nuclear Power at least quarterly.

b. Audit reports encompassed by Section 6.5.2.7 above shall be forwarded to the Manager, Office of Nuclear Power and to the management positions responsible for the areas audited within 30 days after completion of the audit.

See Insert (attached)

~~RECORDS~~

~~6.5.2.7 Records of NSS activities shall be approved and distributed as indicated below:~~

~~a. Reports of reviews encompassed by Specification 6.5.2.5 above, shall be approved by the Chief, NSS, and forwarded to the Manager, Office of Nuclear Power, within 14 days following completion of the review; and~~

~~b. Audit reports encompassed by Specification 6.5.2.6 above, shall be forwarded to the Manager, Office of Nuclear Power, and to the management positions responsible for the areas audited within 30 days after completion of the audit.~~

6.5.3 RADIOLOGICAL ASSESSMENT REVIEW COMMITTEE (RARC)

FUNCTION

6.5.3.1 The RARC shall function to advise the Manager, Radiological Health ~~Manager, Radiological Services~~, and the Plant Manager on all matters related to radiological assessments involving dose calculations and projections and environmental monitoring.

COMPOSITION

6.5.3.2 The RARC shall be composed of the:

Chairman:	Dose Assessment Unit Supervisor Radiological Health
Member:	Health Physicist, Gaseous, ~~Health Physics~~ Service
Member:	Health Physicist, Liquid, ~~Health Physics~~ Service Radiological Health
Member:	Meteorologist ~~Engineer~~, Air Quality Branch
Member:	Chemical Unit Supervisor, Engineering Section, WBNP

ALTERNATES

6.5.3.3 All alternate members shall be appointed in writing by the RARC Chairman to serve on a temporary basis; however, no more than two alternates shall participate as voting members in RARC activities at any one time.

MEETING FREQUENCY

6.5.3.4 The RARC shall meet at least once per 6 months and as convened by the RARC Chairman or his designated alternate.

QUORUM

6.5.3.5 The quorum of the RARC necessary for the performance of the RARC responsibility and authority provisions of these Technical Specifications shall consists of the Chairman or his designated alternate and three members including alternates.

RESPONSIBILITIES

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6.5.3.6 The RARC shall be responsible for:

a. Review of changes to the OFFSITE DOSE CALCULATION MANUAL,

b. Review of ~~all~~ procedures ~~to implement~~ directly implementing the ODCM, the Quality Assurance Program ~~for~~ radiological monitoring, the offsite dose surveillance requirements, environmental radiological monitoring requirements and changes thereto,

c. Review of the results of any audits of the Quality Assurance Program for effluent and environmental monitoring and radiological assessments involving dose calculations and projections, and

d. Review of proposed changes to the Technical Specifications related to radiological assessments involving dose calculations and projections and environmental monitoring.

6.5.3.7 The RARC shall:

a. Recommend in writing to the ~~Manager, Radiological Services,~~ Manager, Radiological Health approval or disapproval of items considered under Specification 6.5.3.6 above,

b. Render determinations in writing with regard to whether or not each item considered under Specification 6.5.3.6 constitutes an unreviewed safety question, and

c. Provide written notification within 24 hours to the Site Director and the Chief, Nuclear Safety Staff, of disagreement between the RARC and the ~~Manager, Radiological Services~~ Manager, Radiological Health; however, the ~~Manager, Radiological Services,~~ Manager, Radiological Health shall have responsibility for resolution of such disagreement pursuant to Specification 6.1.2 above.

RECORDS

6.5.3.8 The RARC shall maintain written minutes of each RARC meeting that, as a minimum, document the results of all RARC activities performed under the responsibility and authority provisions of these technical specifications. Copies shall be provided to the Site Director, PORC, and the Chief, Nuclear Safety Staff.

6.6 REPORTABLE EVENT ACTION

6.6.1 The following actions shall be taken for REPORTABLE EVENTS:

a. The Commission shall be notified and a report submitted pursuant to the requirements of Section 50.73 to 10 CFR Part 50, and

b. Each REPORTABLE EVENT shall be reviewed by the PORC and a copy submitted to the Chief, NSS, and the Site Director.

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6.7 SAFETY LIMIT VIOLATION

6.7.1 The following actions shall be taken in the event a Safety Limit is violated:

a. The NRC Operations Center shall be notified by telephone as soon as possible and in all cases within 1 hour. The Site Director, and the Chief, NSS, shall be notified with 24 hours;

b. A Safety Limit Violation Report shall be prepared. The report shall be reviewed by the PORC. This report shall describe: (1) applicable circumstances preceding the violation, (2) effects of the violation upon facility components, systems or structures, and (3) corrective action taken to prevent recurrence;

c. The Safety Limit Violation Report shall be submitted to the Commission, the Chief, NSS, and the Site Director within 14 days of the violation; and

d. Operation of the unit shall not be resumed until authorized by the Commission.

6.8 PROCEDURES AND PROGRAMS

6.8.1 Written procedures shall be established, implemented, and maintained covering the activities referenced below:

a. The applicable procedures recommended in Appendix A of Regulatory Guide 1.33, Revision 2, February 1978;

b. The emergency operating procedures required to implement the requirements of NUREG-0737 and Supplement 1 to NUREG-0737 as stated in Section 7.1 of Generic Letter No. 82-33;

c. Plant Physical Security Plan implementation;

d. Site Radiological Emergency Plan implementation;

e. PROCESS CONTROL PROGRAM implementation; and

f. Quality Assurance Program for effluent monitoring.

g. Fire Protection Program implementation.

6.8.2 Each procedure of Specification 6.8.1 above, and changes thereto, shall be ~~reviewed by the PORC and approved by the Plant Manager~~ prior to implementation and reviewed periodically as set forth in administrative procedures.

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PROCEDURES AND PROGRAMS (Continued)

6.8.3 Temporary changes to procedures of Specification 6.8.1 above may be made provided:

a. The intent of the original procedure is not altered,

b. The change is approved by two members of the plant management staff, at least one of whom holds a Senior Operator license on the unit affected, and

c. The change is documented, reviewed by the PORC and approved by the Plant Manager within 14 days of implementation.

6.8.4 Written procedures shall be established, implemented and maintained by the Radiological ~~Services~~ Health covering the activities below:

a. OFFSITE DOSE CALCULATIONAL MANUAL implementation,

b. Quality Assurance Program for environmental radiological monitoring, and

c. Surveillance requirements and environmental monitoring requirements shown in Table 6.1-1.

6.8.5 The following programs shall be established, implemented, and maintained:

a. Reactor Coolant Sources Outside Containment

A program to reduce leakage from those portions of systems outside containment that could contain highly radioactive fluids during a serious transient or accident to as low as practical levels. The systems include the Safety Injection System, RHR System, Chemical and Volume Control System, Containment Spray System, and RCS Sampling System. The program shall include the following:

1) Preventive maintenance and periodic visual inspection requirements, and

2) Integrated leak test requirements for each system at refueling cycle intervals or less.

b. In-Plant Radiation Monitoring

A program which will ensure the capability to accurately determine the airborne iodine concentrations in vital areas under accident conditions. This program shall include the following:

1) Training of personnel,

2) Procedures for monitoring, and

3) Provisions for maintenance of sampling and analysis equipment.

PROCEDURES AND PROGRAMS (Continued)

c. Secondary Water Chemistry

A program for monitoring of secondary water chemistry to inhibit steam generator tube degradation. This program shall include:

1) Identification of a sampling schedule for the critical variables and control points for these variables,

2) Identification of the procedures used to measure the values of the critical variables,

3) Identification of process sampling points,

4) Procedures for the recording and management of data,

5) Procedures defining corrective actions for off-control point chemistry conditions,

6) Procedures identifying: (1) the authority responsible for the interpretation of the data; and (2) the sequence and timing of administrative events required to initiate corrective ACTION, and

7) Monitoring of the condensate at the discharge of the condensate pumps for evidence of condenser in-leakage. When condenser in-leakage is confirmed, the leak shall be repaired, plugged, or isolated.

d. Post-accident Sampling

A program which will ensure the capability to obtain and analyze reactor coolant, radioactive iodines and particulates in plant gaseous effluents, and containment atmosphere samples under accident conditions. The program shall include the following:

1) Training of personnel,

2) Procedures for sampling and analysis, and

3) Provisions for maintenance of sampling and analysis equipment.

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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 NRC Regional Office unless otherwise noted.

STARTUP REPORT

6.9.1.1 A summary report of plant 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 plant.

6.9.1.2 The Startup Report shall address each of the tests identified in the FSAR and shall include a description of the measured values of the operating conditions or characteristics obtained during the test program and a comparison of these values with design predictions and specifications. Any corrective actions that were required to obtain satisfactory operation shall also be described. Any additional specific details required in license conditions based on other commitments shall be included in this report.

6.9.1.3 Startup Reports shall be submitted within: (1) 90 days following completion of the Startup Test Program, (2) 90 days following resumption or commencement of commercial power operation, or (3) 9 months following initial criticality, whichever is earliest. If the Startup Report does not cover all three events (i.e., initial criticality, completion of Startup Test Program, and resumption or commencement of commercial power operation), supplementary reports shall be submitted at least every 3 months until all three events have been completed.

ANNUAL REPORTS*

6.9.1.4 Annual Reports covering the activities of the unit as described below for the previous calendar year shall be submitted prior to March 1 of each year. The initial report shall be submitted prior to March 1 of the year following initial criticality.

6.9.1.5 Reports required on an annual basis shall include a tabulation on an annual basis for the number of station, utility and other personnel (including contractors) receiving exposures greater than 100 mrem/yr and their associated man-rem exposure according to work and job functions,** e.g., reactor operations and surveillance, inservice inspection, routine maintenance, special maintenance (describe maintenance), waste processing, and refueling. The dose assignment to various duty functions may be estimates based on pocket dosimeter, TLD, or

*A single submittal may be made for a multiple unit station.

**This tabulation supplements the requirements of 10 CFR Part 20.407.

JUSTIFICATION FOR PROPOSED CHANGES

Specification 6.9.1.6, page 6-19--This proposed change reflects the previous revision submitted by TVA to clarify the scope of the annual radiological environmental operating reports which, according to Outstanding Issue #27, is currently under review by the Nuclear Regulatory Commission staff. The following is provided in support of the proposed change.

TVA's computerized report format generates summarized data in accordance with the Radiological Assessment Branch Technical Position, Revision 1, November 1979. Reports issued for TVA's two operating nuclear plants, in accordance with their respective technical specifications, utilize the same format based on this guideline. The requirement to include the results of all analyses in the Watts Bar Nuclear Plant report would make the report inconsistent with the others issued by TVA. Use of a consistent format for all plants would facilitate comparisons among the reports.

We do not believe that the production of reports in different formats is cost effective. Additionally, the inclusion of all individual sample results would make the reports bulky and difficult to evaluate for both technical reviewers and the general public. The data are available at TVA for review at any time.

ANNUAL REPORTS (Continued)

film badge measurements. Small exposures totalling less than 20% of the individual total dose need not be accounted for. In the aggregate, at least 80% of the total whole body dose received from external sources shall be assigned to specific major work functions.

ANNUAL RADIOLOGICAL ENVIRONMENTAL OPERATING REPORT*

6.9.1.6 Routine Radiological Environmental Operating Reports covering the operation of the unit during the previous calendar year shall be submitted prior to May 31 of each year. The initial report shall be submitted prior to May 31 of the year following initial criticality.

The Annual Radiological Environmental Operating Reports shall include summaries, interpretations, and an analysis of trends of the results of the radiological environmental surveillance activities for the report period, including a comparison with preoperational studies, with operational controls and with previous environmental surveillance reports, and an assessment of the observed impacts of the plant operation on the environment. The reports shall also include the results of the Land Use Census required by Specification 3.12.2.

The Annual Radiological Environmental Operating Reports shall include the ~~results of~~ analysis of ~~all radiological environmental samples and of all~~ environmental radiation measurements taken during the report period pursuant to the locations specified in the table and figures in the ODCM, ~~as well as~~ summarized and tabulated results of ~~these analyses and measurements~~ in the format of the table in the Radiological Assessment Branch Technical Position, Revision 1, November 1979. In the event that some individual results are not available for inclusion with the report, the report shall be submitted noting ~~and explaining the reasons for the~~ missing results. The missing data shall be submitted as soon as possible in a supplementary report.

The reports shall also include the following: a summary description of the Radiological Environmental Monitoring Program; at least two legible maps** covering all sampling locations keyed to a table giving distances and directions from the centerline of one reactor; the results of licensee participation in the Interlaboratory Comparison Program and the corrective actions being taken if the specified program is not being performed as required by Specification 3.12.3; discussion of all deviations from the sampling schedule of Table 3.12-1; reasons for not conducting the Radiological Environmental Monitoring Program as required by Specification 3.1.2.1 and discussion of environmental sample measurements that exceed the reporting levels of Table 3.12-2 but are not the result of plant effluents, pursuant to ACTION b. of Specification 3.12.1; and discussion of all analyses in which the LLD required by Table 4.12-1 was not achievable.

*A single submittal may be made for a multiple unit station.

**One map shall cover stations near the SITE BOUNDARY; a second shall include the more distant stations.

SEMIANNUAL RADIOACTIVE EFFLUENT RELEASE REPORT*

6.9.1.7 Routine Semiannual Radioactive Effluent Release Reports covering the operation of the unit during the previous 6 months of operation shall be submitted within 60 days after January 1 and July 1 of each year. The period of the first report shall begin with the date of initial criticality.

The Semiannual Radioactive Effluent Release Reports shall include a summary of the quantities of radioactive liquid and gaseous effluents and solid waste released from the unit as outlined in Regulatory Guide 1.21, "Measuring, Evaluating, and Reporting Radioactivity in Solid Wastes and Releases of Radioactive Materials in Liquid and Gaseous Effluents from Light-Water-Cooled Nuclear Power Plants," Revision 1, June 1974, with data summarized on a quarterly basis following the format of Appendix B thereof. For solid wastes, the format for Table 3 in Appendix B shall be supplemented with three additional categories; class of solid wastes (as defined by 10 CFR Part 61), type of container (e.g., LSA, Type A, Type B, Large Quantity), and SOLIDIFICATION agent or absorbent (e.g., cement, urea formaldehyde).

The Semiannual Radioactive Effluent Release Report to be submitted 60 days after January 1 of each year shall include an annual summary of hourly meteorological data collected over the previous year. This annual summary may be either in the form of an hour-by-hour listing on magnetic tape of wind speed, wind direction, atmospheric stability, and precipitation (if measured), or in the form of joint frequency distributions of wind speed, wind direction, and atmospheric stability.** This same report shall include an assessment of the radiation doses due to the radioactive liquid and gaseous effluents released from the unit or station during the previous calendar year. This same report shall also include an assessment of the radiation doses from radioactive liquid and gaseous effluents to MEMBERS OF THE PUBLIC due to their activities inside the SITE BOUNDARY (Figure 5.1-3) during the report period. All assumptions used in making these assessments, i.e., specific activity, exposure time and location, shall be included in these reports. The meteorological conditions concurrent with the time of release of radioactive materials in gaseous effluents, as determined by sampling frequency and measurement, shall be used for determining the gaseous pathway doses. The assessment of radiation doses shall be performed in accordance with the methodology and parameters in the OFFSITE DOSE CALCULATION MANUAL (ODCM).

*A single submittal may be made for a multiple unit station. The submittal should combine those sections that are common to all units at the station; however, for units with separate Radwaste Systems, the submittal shall specify the releases of radioactive material from each unit.

**In lieu of submission with the Semiannual Radioactive Effluent Release Report, the licensee has the option of retaining this summary of required meteorological data on site in a file that shall be provided to the NRC upon request.

SEMIANNUAL RADIOACTIVE EFFLUENT RELEASE REPORT (Continued)

The Semiannual Radioactive Effluent Release Report to be submitted within 60 days after January 1 of each year shall also include an assessment of radiation doses to the likely most exposed MEMBER OF THE PUBLIC from reactor releases and other nearby uranium fuel cycle sources, including doses from primary effluent pathways and direct radiation, for the previous calendar year to show conformance with 40 CFR Part 190, "Environmental Radiation Protection Standards for Nuclear Power Operation." Acceptable methods for calculating the dose contribution from liquid and gaseous effluents are given in Regulatory Guide 1.109, Rev. 1, October 1977.

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

The Semiannual Radioactive Effluent Release Reports shall include any changes made during the reporting period to the PROCESS CONTROL PROGRAM (PCP) and to the OFFSITE DOSE CALCULATION MANUAL (ODCM), pursuant to Specification 6.13 and 6.14, respectively, as well as any major changes to Liquid, Gaseous or Solid Radwaste Treatment Systems, pursuant to Specification 6.15. It shall also include a listing of new locations for dose calculations and/or environmental monitoring identified by the Land Use Census pursuant to Specification 3.12.2.

The Semiannual Radioactive Effluent Release Reports shall also include the following: an explanation as to why the inoperability of liquid or gaseous effluent monitoring instrumentation was not corrected within the time specified in Specifications 3.3.3.10 or 3.3.3.11, respectively; and description of the events leading to liquid holdup tanks or gas storage tanks exceeding the limits of Specifications 3.11.1.4 or 3.11.2.6, respectively.

MONTHLY OPERATING REPORTS

6.9.1.8 Routine reports of operating statistics and shutdown experience, including documentation of all challenges to the PORVs or Safety Valves, shall be submitted on a monthly basis to the Director, Office of Resource Management, U.S. Nuclear Regulatory Commission, Washington, D.C. 20555, with a copy to the Regional Administrator of the NRC Regional Office, no later than the 15th of each month following the calendar month covered by the report.

RADIAL PEAKING FACTOR LIMIT REPORT

6.9.1.9 The F_{xy} limits for RATED THERMAL POWER (F_{xy}^{RTP}) shall be provided to the NRC Regional Administrator with a copy to Director of Nuclear Reactor Regulation, Attention: Chief, Core Performance Branch, U. S. Nuclear Regulatory Commission, Washington, D. C. 20555, for all core planes containing Bank "D" control rods and all unrodded core planes and the plot of predicted ($F_q^T \cdot P_{Rel}$) vs Axial Core Height with the limit envelope at least 60 days prior to each cycle initial criticality unless otherwise approved by the Commission by letter.

RADIAL PEAKING FACTOR LIMIT REPORT (Continued)

In addition, in the event that the limit should change requiring a new submittal to the Peaking Factor Limit Report, it shall be submitted 60 days prior to the date the limit would become effective unless otherwise approved by the Commission by letter. Any information needed to support F_{xy}^{RTP} will be by request from the NRC and need not be included in this report.

SPECIAL REPORTS

6.9.2 Special reports shall be submitted to the Regional Administrator of the NRC Regional Office within the time period specified for each report.

6.10 RECORD RETENTION

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.

6.10.1 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;

c. All REPORTABLE EVENTS;

d. Records of surveillance activities, inspections and calibrations required by these Technical Specifications;

e. Records of changes made to the procedures required by Specifications 6.8.1 and 6.8.4;

f. Records of radioactive shipments;

g. Records of sealed source and fission detector leak tests and results; and

h. Records of annual physical inventory of all sealed source material of record.

6.10.2 The following records shall be retained for the duration of the unit Operating License:

a. Records and drawing changes reflecting unit design modifications made to systems and equipment described in the Final Safety Analysis Report;

b. Records of new and irradiated fuel inventory, fuel transfers and assembly burnup histories;

c. Records of radiation exposure for all individuals entering radiation control areas;

d. Records of gaseous and liquid radioactive material released to the environs;

RECORD RETENTION (Continued)

e. Records of transient or operational cycles for those unit components identified in Table 5.7-1;

f. Records of reactor tests and experiments;

g. Records of training and qualification for current members of the unit staff;

h. Records of inservice inspections performed pursuant to these Technical Specifications;

i. Records of Quality Assurance activities required by the Operational Quality Assurance Manual;

j. Records of reviews performed for changes made to procedures or equipment or reviews of tests and experiments ~~pursuant to 10 CFR 50.59~~;

k. Records of meetings of the PORC and RARC and of the NSS reports of ~~reviews and audits~~; the results of reviews and of cognizance of audits

l. Records of analyses required by the Radiological Environmental Monitoring Program that would permit evaluation of the accuracy of the analysis at a later date. This should include procedures effective at specified times and QA records showing that these procedures were followed;

m. Records of secondary water sampling and water quality; and

n. Records of the service lives of all hydraulic and mechanical snubbers required by Specification 3.7.9 including the date at which the service life commences and associated installation and maintenance records.

6.11 RADIATION PROTECTION PROGRAM

Procedures for personnel radiation protection shall be prepared consistent with the requirements of 10 CFR Part 20 and shall be approved, maintained, and adhered to for all operations involving personnel radiation exposure.

6.12 HIGH RADIATION AREA

6.12.1 Pursuant to Paragraph 20.203(c)(5) of 10 CFR Part 20, in lieu of the "control device" or "alarm signal" required by Paragraph 20.203(c) each high radiation area, as defined in 10 CFR Part 20, in which the intensity of radiation is equal to or less than 1000 mR/h at 45 cm (18 in.) from the radiation source or from any surface which the radiation penetrates shall be barricaded and conspicuously posted as a high radiation area and entrance thereto shall be controlled by requiring issuance of a Radiation Work Permit (RWP). Individuals qualified in radiation protection procedures (e.g., Health Physics Technician) or personnel continuously escorted by such individuals may be exempt from the RWP issuance requirement during the performance of their assigned duties in high radiation areas with exposure rates equal to or less than 1000 mR/h, provided they are otherwise following plant radiation protection procedures for entry into such high radiation areas. Any individual or group of individuals permitted to enter such areas shall be provided with or accompanied by one or more of the following:

HIGH RADIATION AREA (Continued)

a. A radiation monitoring device which continuously indicates the radiation dose rate in the area, or

b. A radiation monitoring device which continuously integrates the radiation dose rate in the area and alarms when a preset integrated dose is received. Entry into such areas with this monitoring device may be made after the dose rate levels in the area have been established and personnel have been made knowledgeable of them; or

c. An individual qualified in radiation protection procedures with a radiation dose rate monitoring device, who is responsible for providing positive control over the activities within the area and shall perform periodic radiation surveillance at the frequency specified by the Health Physics Supervisor in the RWP.

6.12.2 In addition to the requirements of Specification 6.12.1, areas accessible to personnel with radiation levels greater than 1000 mR/h at 45 cm (18 in.) from the radiation source or from any surface which the radiation penetrates shall be provided with locked doors to prevent unauthorized entry, and the keys shall be maintained under the administrative control of the Shift Foreman on duty and/or health physics supervision. Doors shall remain locked except during periods of access by personnel under an approved RWP which shall Specify the dose rate levels in the immediate work areas and the maximum allowable stay time for individuals in that area. In lieu of the stay time specification of the RWP, direct or remote (such as closed circuit TV cameras) continuous surveillance may be made by personnel qualified in radiation protection procedures to provide positive exposure control over the activiites being performed within the area.

For individual high radiation areas accessible to personnel with radiation levels of greater than 1000 mR/h that are located within large areas, such as PWR containment, where no enclosure exists for purposes of locking, and where no enclosure can be reasonably constructed around the individual area, that individual area shall be barricaded, conspicuously posted, and a flashing light shall be activiated as a warning device.

6.13 PROCESS CONTROL PROGRAM (PCP)

6.13.1 The PCP shall be approved by the Commission prior to implementation.

6.13.2 Licensee-initiated changes to the PCP:

a. Shall be submitted to the Commission in the Semiannual Radioactive Effluent Release Report for the period in which the change(s) was made. This submittal shall contain:

1) Sufficiently detailed information to totally support the rationale for the change without benefit of additional or supplemental information;

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2) A determination that the change did not reduce the overall conformance of the solidified waste product to existing criteria for solid wastes; and

3) Documentation of the fact that the change has been reviewed and found acceptable by the PORC.

b. Shall become effective upon review and acceptance by the PORC.

6.14 OFFSITE DOSE CALCULATION MANUAL (ODCM)

6.14.1 The ODCM shall be approved by the Commission prior to implementation.

6.14.2 Licensee-initiated changes to the ODCM:

a. Shall be submitted to the Commission in the Semiannual Radioactive Effluent Release Report for the period in which the change(s) was made effective. This submittal shall contain:

1) Sufficiently detailed information to totally support the rationale for the change without benefit of additional or supplemental information. Information submitted should consist of a package of those pages of the ODCM to be changed with each page numbered, dated and containing the revision number, together with appropriate analyses or evaluations justifying the change(s);

2) A determination that the change will not reduce the accuracy or reliability of dose calculations or Setpoint determinations; and

3) Documentation of the fact that the change has been reviewed and found acceptable by the RARC.

b. Shall become effective upon review and acceptance by the RARC.

6.15 MAJOR CHANGES TO LIQUID, GASEOUS, AND SOLID RADWASTE TREATMENT SYSTEMS*

6.15.1 Licensee-initiated major changes to the Radwaste Treatment Systems (liquid, gaseous, and solid):

a. Shall be reported to the Commission in the Semiannual Radioactive Effluent Release Report for the period in which the evaluation was reviewd by the PORC. The discussion of each change shall contain:

1) A summary of the evaluation that led to the determination that the change could be made in accordance with 10 CFR 50.59;

*Licensees may choose to submit the information called for in this specification as part of the annual FSAR update.

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MAJOR CHANGES TO LIQUID, GASEOUS, AND SOLID RADWASTE TREATMENT SYSTEMS (Continued)

2) Sufficient detailed information to totally support the reason for the change without benefit of additional or supplemental information;

3) A detailed description of the equipment, components, and processes involved and the interfaces with other plant systems;

4) An evaluation of the change, which shows the predicted releases of radioactive materials in liquid and gaseous effluents and/or quantity of solid waste that differ from those previously predicted in the license application and amendments thereto;

5) An evaluation of the change, which shows the expected maximum exposures to individual in the UNRESTRICTED AREA and to the general population that differ from those previously estimated in the license application and amendments thereto;

6) A comparison of the predicted releases of radioactive materials, in liquid and gaseous effluents and in solid waste, to the actual releases for the period prior to when the changes are to be made;

7) An estimate of the exposure to plant operating personnel as a result of the change; and

8) Documentation of the fact that the change was reviewed and found acceptable by the PORC.

b. Shall become effective upon review and acceptance by the PORC.