Indian Point
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Improved

Technical Specifications

Conversion Submittal

Volume 17

New York Power
Authority

4 SURVEILLANCE REQUIREMENTS

4.1 OPERATIONAL SAFETY REVIEW

~~Applicability~~

~~Applies to items directly related to safety limits and limiting conditions for operation.~~ Performance of any surveillance test outlined in these specifications is not required if the plant condition is the same as the condition into which the plant would be placed by an unsatisfactory result of that test. Failure to perform a surveillance requirement within the allowed surveillance interval (including extensions specified in definition 1.12), shall constitute noncompliance with the operability requirements of the limiting conditions for operation (LCOs). The time limits for associated action requirements are applicable at the time it is identified that a surveillance requirement has not been performed. Action requirements may be delayed for up to 24 hours to permit completion of the missed surveillance when the allowable outage time limits of the action requirements are less than 24 hours (i.e. for LCOs of less than 24 hours, a 24 hour delay period is permitted before entering the LCO; for LCOs greater than 24 hours, no delay period is permitted).

SR 3.0.1 — A.2, A.10

SR 3.0.2 — A.11

SR 3.0.3 — L.2

a 24 hour — L.2

~~Objective~~

~~To specify the minimum frequency and type of surveillance to be applied to plant equipment and conditions.~~ — A.2

SEE ITS 3.3

Specification

A. Calibration, testing, and checking of analog channel and testing of logic channel shall be performed as specified in Table 4.1-1.

B. Sampling and equipment tests shall be conducted as specified in Table 4.1-2 and 4.1-3, respectively.

~~Basis~~

~~A surveillance test is intended to identify conditions in a plant that would lead to a degradation of reactor safety. Should a test reveal such a condition, then the Technical Specifications require that, either immediately or after a specified period of time, the plant be placed in a condition which mitigates or eliminates the consequences of additional related casualties or accidents. If the plant is already in a condition~~ — A.1

Add SR 3.0.4 — M.1

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Specification

LCO 3.3.1
SR Table
Note

~~A.~~ Calibration, testing, and checking of analog channel and testing of logic channel shall be performed as specified in Table 4.1-1 3.3.1-1 A.1

~~B.~~ Sampling and equipment tests shall be conducted as specified in Table 4.1-2 and 4.1-3, respectively.

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LCO 3.3.2 SR TABLE Note

A. Calibration, testing, and checking of analog channel and testing of logic channel shall be performed as specified in Table ~~4.1-1~~ 3.3.2-1

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condition which would satisfy the failure criteria of the test, then plant safety is assured and performance of the test yields either meaningless information or information that is not necessary to determine safety limits or limiting conditions for operation of the plant.

Likewise, systems and components are assumed to be operable as defined in paragraph 1.5, and satisfying safety limits or LCOs for a given plant operating condition, when surveillance requirements have been satisfactorily performed within the allowed surveillance interval and extensions as specified in definition 1.12. However, nothing in this provision shall be construed as implying that systems or components are operable when they are found or known to be inoperable although still meeting the surveillance requirements. LCO action requirements associated with operation in a degraded mode are applicable when surveillance requirements have not been completed within the allowed surveillance interval. The time limits of such LCOs apply from the point in time it is identified that a surveillance has not been performed and not at the time the allowed surveillance interval was exceeded.

For a missed surveillance, if the allowable outage time limits of the applicable LCO action requirements are less than 24 hours or a shutdown is required, then a 24-hour delay is permitted in implementing the action requirements. The purpose of the delay is to permit the completion of a missed surveillance before a shutdown or some other remedial measure precludes completion of the surveillance. This allowance of a delay includes consideration of the plant conditions, adequate planning, availability of personnel, the time required to perform the surveillance, and the safety significance of the delay in completing the required surveillance. If a surveillance is not completed within the 24-hour delay, than the time limits of the associated action requirements are applicable at the time. When a surveillance is performed within the 24-hour delay and the Surveillance Requirements are not met (e.g. the system or component is declared inoperable), the time limits of the LCO action requirements are applicable at that time.

Failure to perform the surveillance within the allowed surveillance interval and extension as specified in definition 1.12 is still a violation of the LCO operability requirement subject to enforcement and reportability requirements as may be applicable.

Definition 1.12 establishes the limit for which the specified time interval for Surveillance Requirements may be extended.

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Definition 1.12 establishes the limit for which the specified time interval for Surveillance Requirements may be extended.

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It permits an allowable extension of the normal surveillance interval to facilitate surveillance scheduling and consideration of plant operating conditions that may not be suitable for conducting the surveillance; e.g. transient conditions or other ongoing surveillance or maintenance activities. It also provides flexibility to accommodate the length of a fuel cycle for surveillances that are performed at each refueling outage and are specified with an 18-month or 24-month surveillance interval. It is not intended that this provision be used repeatedly as a convenience to extend surveillance intervals beyond that specified for surveillances that are not performed on an 18-month or 24-month basis. Likewise, it is not the intent that 24 month surveillances be performed during power operation unless it is consistent with safe plant operation. The limitation of Definition 1.12 is based on engineering judgement and the recognition that the most probable result of any particular surveillance being performed is the verification of conformance with the Surveillance Requirements. This provision is sufficient to ensure that the reliability ensured through surveillance activities is not significantly degraded beyond that obtained from the specified surveillance interval. The phrase "at least" associated with a surveillance frequency does not negate the 25% extension allowance of Definition 1.12; instead, it permits the performance of more frequent surveillance activities.

Based on experience in operation of both conventional and nuclear plant systems, when the plant is in operation, the minimum checking frequency of once per shift is deemed adequate for reactor and steam system instrumentation.

Calibration

Calibrations are performed to ensure the presentation and acquisition of accurate information.

The nuclear flux (linear level) channels are calibrated daily against a heat balance standard to account for errors induced by changing rod patterns and core physics parameters.

Other channels are subject only to the "drift" errors induced within the instrumentation itself and, consequently, can tolerate longer intervals between calibration. Process system instrumentation errors induced by drift can be expected to remain within acceptable tolerances if recalibration is performed at intervals of 18 or 24 months.

Substantial calibration shifts within a channel (essentially a channel failure) will be revealed during routine checking and testing procedures.

Thus, minimum calibration frequencies of once-per-day for the nuclear flux (linear level) channels, and 18 or 24 months for the process system channels is considered acceptable.

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Testing

The minimum testing frequency for those instrument channels connected to the safety system is based on an average unsafe failure rate of 2.5×10^{-6} failure hrs. per channel. This is based on operating experience at conventional and nuclear plants. An unsafe failure is defined as one which negates channel operability and which, due to its nature, is revealed only when the channel is tested or attempts to respond to a bona fide signal.

For a specified test interval W and an M out of N redundant system with identical and independent channels having a constant failure rate λ, the average availability A is given by:

$$A = \frac{W - Q\left(\frac{W}{N-M+2}\right)}{W} = 1 - \frac{N!}{(N-M+2)!\,(M-1)!}(\lambda W)^{N-M+1}$$

where A is defined as the fraction of time during which the system is functional, and Q is the probability of failure of such a system during a time interval W.

For a 2-out-of-3 system A = 0.9999708, assuming a channel failure rate, λ, equal to 2.5×10^{-6} hr $^{-1}$ and a test interval, W, equal to 2160 hrs.

This average availability of the 2-out-of-3 system is high, hence the test interval of one quarter is acceptable.

Because of their greater degree of redundancy, the 1/3 and 2/4 logic arrays provide an even greater measure of protection and are thereby acceptable for the same testing interval. Those items specified for quarterly testing are associated with process components where other means of verification provide additional assurance that the channel is operable, thereby requiring less frequent testing.

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Amendment No. 93, 96, 97, 107

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~~Specified surveillance intervals for the Reactor Protection System and Engineered Safety Features have been determined in accordance with WCAP - 10271, Supplement 1, "Evaluation of Surveillance Frequencies and Out of Service Times for the Reactor Protection Instrumentation System," and WCAP - 10271, Supplement 2, Revision 1, "Evaluation of Surveillance Frequencies and Out of Service Times for the Engineered Safety Features Actuation System," as approved by the NRC and documented in the SERs (letters to J. J. Sheppard from C. O. Thomas, dated February 21, 1985, and to R. A. Newton from C. E. Rossi, dated February 22, 1989). Surveillance intervals were determined based on maintaining an appropriate level of reliability of the Reactor Protection System and Engineered Safety Features instrumentation.~~

A.1

DELETED

~~Specified surveillance intervals for the Reactor Protection System and Engineered Safety Features have been determined in accordance with WCAP - 10271, Supplement 1, "Evaluation of Surveillance Frequencies and Out of Service Times for the Reactor Protection Instrumentation System," and WCAP - 10271, Supplement 2, Revision 1, "Evaluation of Surveillance Frequencies and Out of Service Times for the Engineered Safety Features Actuation System," as approved by the NRC and documented in the SERs (letters to J. J. Sheppard from C. O. Thomas, dated February 21, 1985, and to R. A. Newton from C. E. Rossi, dated February 22, 1989). Surveillance intervals were determined based on maintaining an appropriate level of reliability of the Reactor Protection System and Engineered Safety Features instrumentation.~~

DELETED

A.1

Amendment No. ~~93~~, ~~107~~, TSCR 97-156

~~Specified surveillance intervals for the Reactor Protection System and Engineered Safety Features have been determined in accordance with WCAP - 10271, Supplement 1, "Evaluation of Surveillance Frequencies and Out of Service Times for the Reactor Protection Instrumentation System," and WCAP - 10271, Supplement 2, Revision 1, "Evaluation of Surveillance Frequencies and Out of Service Times for the Engineered Safety Features Actuation System," as approved by the NRC and documented in the SERs (letters to J. J. Sheppard from C. O. Thomas, dated February 21, 1985, and to R. A. Newton from C. E. Rossi, dated February 22, 1989). Surveillance intervals were determined based on maintaining an appropriate level of reliability of the Reactor Protection System and Engineered Safety Features instrumentation.~~

DELETED

~~Specified surveillance intervals for the Reactor Protection System and Engineered Safety Features have been determined in accordance with WCAP - 10271, Supplement 1, "Evaluation of Surveillance Frequencies and Out of Service Times for the Reactor Protection Instrumentation System," and WCAP - 10271, Supplement 2, Revision 1, "Evaluation of Surveillance Frequencies and Out of Service Times for the Engineered Safety Features Actuation System," as approved by the NRC and documented in the SERs (letters to J. J. Sheppard from C. O. Thomas, dated February 21, 1985, and to R. A. Newton from C. E. Rossi, dated February 22, 1989). Surveillance intervals were determined based on maintaining an appropriate level of reliability of the Reactor Protection System and Engineered Safety Features instrumentation.~~

DELETED

Add SR 3.3.1.11 for NIs — SR 3.3.1.3, Freq (L.5) — (M.7)

TABLE 4.1-1 (Sheet 1 of 6)

SR 3.3.1.6 (L.5) — Add SR 3.3.1.8 Freq (L.4) (M.4)

MINIMUM FREQUENCIES FOR CHECKS, CALIBRATIONS AND TESTS OF INSTRUMENT CHANNELS

	Channel Description	Check	Calibrate	Test	Remarks	
T3.3.1-1, #2a, #2b, #5, #6	1. Nuclear Power Range (A.4) SR 3.3.1.2, Notes 1,2; SR 3.3.1.3, Notes 1,2 (A.8)	~~S~~ 12 hours SR 3.3.1.1 (A.9)	D (1) M (3)* SR 3.3.1.2 SR 3.3.1.3 Add Note	Q (2) Q (4) SR 3.3.1.7 SR 3.3.1.8	1) Heat balance calibration 2) Bistable action (permissive, rod stop, trips) 3) Upper and lower chambers for axial offset 4) Signal to ΔT (LA 2)	A.4 A.5 A.8 A.9
T3.3.1-1, #3	2. Nuclear Intermediate Range	S (1) SR 3.3.1.1	N.A. (M.7) SR 3.3.1.11	P (2) SR 3.3.1.8	1) Once/shift when in service 2) Verification of channel response to simulated inputs	A.6
T3.3.1-1, #4	3. Nuclear Source Range	S (1) SR 3.3.1.1	N.A. (M.7) SR 3.3.1.11	P (2) SR 3.3.1.8	1) Once/shift when in service 2) Verification of channel response to simulated inputs	A.7
T3.3.1-1, #5, #6	4. Reactor Coolant Temperature	S ~~## (2)~~ SR 3.3.1.1	24M SR 3.3.1.12	Q (1) SR 3.3.1.7	1) Overtemperature ΔT, overpower ΔT, and low T_{avg} 2) Normal Instrument check interval is once/shift	A.8 A.9
SEE ITS 3.4.2					T_{avg} instrument check interval reduced to every 30 minutes when: - T_{avg}-T_{ref} deviation and low T_{avg} alarms are not reset and, - Control banks are above 0 steps	
T3.3.1-1, #9a, 9b	5. Reactor Coolant Flow	S ## SR 3.3.1.1	24M SR 3.3.1.10	Q SR 3.3.1.7		A.13 A.14
T3.3.1-1 #8	6. Pressurizer Water Level	S SR 3.3.1.1	24M SR 3.3.1.10	Q SR 3.3.1.7		A.12
T3.3.1-1, 7a, 7b	7. Pressurizer Pressure	S ## SR 3.3.1.1	24M SR 3.3.1.10 SR 3.3.1.12	Q SR 3.3.1.7	High and Low	A.10 A.11
T3.3.1-1, #5						A.8

ITS 3.3.1

Amendment No. 38, 65, 74, 93, 107, 123, 126, 137, 140, 149, 150, 168, 170, TSCR 98-043

Overtemp ΔT (A.8)

Add SR 3.3.2.6 - Test Manual Initiation Capability A.3 A.16 A.10 A.19 A.13

TABLE 4.1-1 (Sheet 1 of 6)

MINIMUM FREQUENCIES FOR CHECKS, CALIBRATIONS AND TESTS OF INSTRUMENT CHANNELS

Channel Description	Check	Calibrate	Test	Remarks
1. Nuclear Power Range	S	D (1) M (3)*	Q (2)** Q (4)	1) Heat balance calibration 2) Bistable action (permissive, rod stop, trips) 3) Upper and lower chambers for axial offset 4) Signal to Δ T
2. Nuclear Intermediate Range	S (1)	N.A.	P (2)	1) Once/shift when in service 2) Verification of channel response to simulated inputs
3. Nuclear Source Range	S (1)	N.A.	P (2)	1) Once/shift when in service 2) Verification of channel response to simulated inputs
4. Reactor Coolant Temperature	S ## (2) SR 3.3.2.1	24M SR 3.3.2.7	Q (1) SR 3.3.2.4	1) Overtemperature ΔT, overpower ΔT, and low T_{avg} 2) Normal Instrument check interval is once/shift T_{avg} instrument check interval reduced to every 30 minutes when: - T_{avg}-T_{ref} deviation and low T_{avg} alarms are not reset and, - Control banks are above 0 steps SEE ITS 3.4.2
SEE ITS 3.4.1				
5. Reactor Coolant Flow	S ##	24M	Q	
6. Pressurizer Water Level	S	24M	Q	
7. Pressurizer Pressure	S ## SR 3.3.2.1	24M SR 3.3.2.7	Q SR 3.3.2.4	~~High and~~ Low LA.

SEE ITS 3.3.1

T3.3.2-1, #1.c #4.d

T 3.3.2-1, #1.d

A.8 A.22 A.30 A.6

ITS 3.3.2

Amendment No. 38, 65, 74, 93, 107, 125, 126, 137, 140, 149, 150, 160, 170, TSCR 98-043

TABLE 4.1-1 (Sheet 1 of 6)

MINIMUM FREQUENCIES FOR CHECKS, CALIBRATIONS AND TESTS OF INSTRUMENT CHANNELS

	Channel Description	Check	Calibrate	Test	Remarks
SEE ITS 3.3.1	1. Nuclear Power Range	S	D (1) M (3)*	Q (2)** Q (4)	1) Heat balance calibration 2) Bistable action (permissive, rod stop, trips) 3) Upper and lower chambers for axial offset 4) Signal to Δ T
	2. Nuclear Intermediate Range	S (1)	N.A.	P (2)	1) Once/shift when in service 2) Verification of channel response to simulated inputs
	3. Nuclear Source Range	S (1)	N.A.	P (2)	1) Once/shift when in service 2) Verification of channel response to simulated inputs
T3.3.3-1, #2 T3.3.3-1, #3	4. Reactor Coolant Temperature SEE ITS 3.3.1	S ## (2) SR 3.3.3.1	24M SR 3.3.3.2	Q (1)	1) Overtemperature ΔT, overpower ΔT, and low T_{avg} 2) Normal Instrument check interval is once/shift T_{avg} instrument check interval reduced to every 30 minutes when: - T_{avg}-T_{ref} deviation and low T_{avg} alarms are not reset and, - Control banks are above 0 steps
SEE ITS 3.3.1	5. Reactor Coolant Flow	S ##	24M	Q	
T3.3.3-1, #12	6. Pressurizer Water Level	SR 3.3.3.1 S 31 days	SR 3.3.3.2 24M L.2	Q	SEE ITS 3.3.1
SEE ITS 3.3.1	7. Pressurizer Pressure	S ##	24M	Q	High and Low

A.4

A.12

ITS 3.3.3

TABLE 4.1-1 (Sheet 1 of 6)

MINIMUM FREQUENCIES FOR CHECKS, CALIBRATIONS AND TESTS OF INSTRUMENT CHANNELS

	Channel Description	Check	Calibrate	Test	Remarks
	1. Nuclear Power Range	S	D (1) M (3)*	Q (2)** Q (4)	1) Heat balance calibration 2) Bistable action (permissive, rod stop, trips) 3) Upper and lower chambers for axial offset 4) Signal to Δ T
	2. Nuclear Intermediate Range	S (1)	N.A.	P (2)	1) Once/shift when in service 2) Verification of channel response to simulated inputs
	3. Nuclear Source Range	S (1)	N.A.	P (2)	1) Once/shift when in service 2) Verification of channel response to simulated inputs
SR 3.4.1.2	4. Reactor Coolant Temperature	S ## (2)	24M	Q (1)	1) Overtemperature ΔT, overpower ΔT, and low T_{avg} 2) Normal instrument check interval is once/shift T_{avg} instrument check interval reduced to every 30 minutes when: - T_{avg}-T_{ref} deviation and low T_{avg} alarms are not reset and, - Control banks are above 0 steps
SR 3.4.1.3	5. Reactor Coolant Flow	S ##	24M	Q	
	6. Pressurizer Water Level	S	18M	Q	
SR 3.4.1.1	7. Pressurizer Pressure	S ##	24M	Q	High and Low

SEE ITS 3.3.1

SEE ITS 3.4.2

Amendment No. 38, 65, 74, 93, 107, 125, 126, 137, 140, 149, 150, 168, 170

ITS 3.4.1

TABLE 4.1-1 (Sheet 1 of 6)

MINIMUM FREQUENCIES FOR CHECKS, CALIBRATIONS
AND TESTS OF INSTRUMENT CHANNELS

	Channel Description	Check	Calibrate	Test	Remarks
1.	Nuclear Power Range	S	D (1) M (3)*	Q (2)** Q (4)	1) Heat balance calibration 2) Bistable action (permissive, rod stop, trips) 3) Upper and lower chambers for axial offset 4) Signal to ΔT
2.	Nuclear Intermediate Range	S (1)	N.A.	P (2)	1) Once/shift when in service 2) Verification of channel response to simulated inputs
3.	Nuclear Source Range	S (1)	N.A.	P (2)	1) Once/shift when in service 2) Verification of channel response to simulated inputs
4.	Reactor Coolant Temperature	S ## (2)	24M Any RCS Loop $T_{avg} < 547$ Mode 1, Mode 2 with $k_{eff} \geq 1.0$	Q (1)	1) Overtemperature ΔT, overpower ΔT, and low T_{avg} 2) Normal instrument check interval is once/shift T_{avg} instrument check interval reduced to every 30 minutes when: L.2 - T_{avg}-T_{ref} deviation and low T_{avg} alarms are not reset and, Control banks are above 0 steps L.3
5.	Reactor Coolant Flow	S ##	24M	Q	
6.	Pressurizer Water Level	S	18M	Q	
7.	Pressurizer Pressure	S ##	24M	Q	High and Low

SR 3.4.2.1

Amendment No. 28, 65, 74, 93, 107, 125, 126, 137, 140, 149, 150, 168, 170

ITS 3.4.2

TABLE 4.1-1 (Sheet 1 of 6)

MINIMUM FREQUENCIES FOR CHECKS, CALIBRATIONS AND TESTS OF INSTRUMENT CHANNELS

Channel Description	Check	Calibrate	Test	Remarks
1. Nuclear Power Range	S	D (1) M (3)*	Q (2)** Q (4)	1) Heat balance calibration 2) Bistable action (permissive, rod stop, trips) 3) Upper and lower chambers for axial offset 4) Signal to Δ T
2. Nuclear Intermediate Range	S (1)	N.A.	P (2)	1) Once/shift when in service 2) Verification of channel response to simulated inputs
3. Nuclear Source Range	S (1) 12 hours	N.A. 24 M	P (2)	1) Once/shift when in service 2) ~~Verification of channel response to simulated inputs~~
4. Reactor Coolant Temperature	S ## (2) SEE TSCR 97-118	24M	Q (1)	1) Overtemperature ΔT, overpower ΔT, and low T_{avg} 2) Normal instrument check interval is once/shift T_{avg} instrument check interval reduced to every 30 minutes when: - T_{avg}-T_{ref} deviation and low T_{avg} alarms are not reset and, - Control banks are above 0 steps
5. Reactor Coolant Flow	S ##	24M	Q	
6. Pressurizer Water Level	S	18M 24M	Q	TSCR 98-043
7. Pressurizer Pressure	S ##	24M	Q	High and Low

SEE CTS MASTER MARKUP

SR 3.9.2.1

SEE CTS MASTER MARKUP

SEE ITS 3.3.1

M2

ITS 3.9.2

TSCR 98-043

12 hours — A9

SEE ITS 3.1.7

LA.2

TABLE 4.1-1 (Sheet 2 of 6)

Channel Description	Check	Calibrate	Test	Remarks
8. 6.9 KV Voltage	N.A.	18M	Q	Reactor protection circuits only
6.9 KV Frequency	N.A.	24M	Q	Reactor protection circuits only
SR 3.1.4.1 9. Analog Rod Position	S	24M	M	
10. Steam Generator Level	S	24M	Q	
11. Residual Heat Removal Pump Flow	N.A.	24M	N.A.	
12. Boric Acid Tank Level	S	24M	N.A.	
13. Refueling Water Storage Tank Level				Bubbler tube rodded during calibration
a. Transmitter	W	18M	N.A.	Low level alarm
b. Indicating Switch	W	6M	N.A.	Low level alarm
14a. Containment Pressure - narrow range	S	24M	Q	High and High-High
14b. Containment Pressure - wide range	M	18M	N.A.	
15. Process and Area Radiation Monitoring:				
a. Fuel Storage Building Area Radiation Monitor (R-5)	D	24M	Q	
b. Vapor Containment Process Radiation Monitors (R-11 and R-12)	D	24M	Q	
c. Vapor Containment High Radiation Monitors (R-25 and R-26)	D	24M	Q	
d. Wide Range Plant Vent Gas Process Radiation Monitor (R-27)	D	24M	Q	

SEE CTS MASTER MARKUP

(A.7)

(M.1)

SEE ITS 3.1.4

Prior to reactor critical after head removal

TABLE 4.1-1 (Sheet 2 of 6)

Channel Description	Check	Calibrate	Test	Remarks
8. 6.9 KV Voltage	N.A.	18M	Q	Reactor protection circuits only
6.9 KV Frequency	N.A.	24M	Q	Reactor protection circuits only
9. Analog Rod Position	S	24M	M	
10. Steam Generator Level	S	24M	Q	
11. Residual Heat Removal Pump Flow	N.A.	24M	N.A.	
12. Boric Acid Tank Level	S	24M	N.A.	Bubbler tube rodded during calibration
13. Refueling Water Storage Tank Level				
a. Transmitter	W	18M	N.A.	Low level alarm
b. Indicating Switch	W	6M	N.A.	Low level alarm
14a. Containment Pressure - narrow range	S	24M	Q	High and High-High
14b. Containment Pressure - wide range	M	18M	N.A.	
15. Process and Area Radiation Monitoring:				
a. Fuel Storage Building Area Radiation Monitor (R-5)	D	24M	Q	
b. Vapor Containment Process Radiation Monitors (R-11 and R-12)	D	24M	Q	
c. Vapor Containment High Radiation Monitors (R-25 and R-26)	D	24M	Q	
d. Wide Range Plant Vent Gas Process Radiation Monitor (R-27)	D	24M	Q	

SR 3.1.7.1

SEE CTS MASTER MARKUP

ITS 3.1.7

TABLE 4.1-1 (Sheet 2 of 6)

A.15 A.16

	Channel Description	Check	Calibrate	Test	Remarks	
T3.3.1-1, #11	8. 6.9 KV Voltage	N.A.	18M SR3.3.1.10	Q SR3.3.1.9	Reactor protection circuits only	A.17
T3.3.1-1, #12	6.9 KV Frequency	N.A.	24M SR3.3.1.14	Q	Reactor protection circuits only	A.18
SEE ITS 3.1.7	9. Analog Rod Position	S	24M	M		
T3.3.1-1, #13 #14	10. Steam Generator Level	S SR3.3.1.1	24M SR3.3.1.10	Q SR3.3.1.7		A.19 A.20
SEE ITS 3.3.3	11. Residual Heat Removal Pump Flow	N.A.	24M	N.A.		
	12. Boric Acid Tank Level	S	24M	N.A.	Bubbler tube rodded during calibration	
	13. Refueling Water Storage Tank Level					
	a. Transmitter	W	18M	N.A.	Low level alarm	
	b. Indicating Switch	W	6M	N.A.	Low level alarm	
SEE ITS 3.3.2	14a. Containment Pressure - narrow range	S	24M	Q	High and High-High	
SEE ITS 3.3.3	14b. Containment Pressure - wide range	M	18M	N.A.		
SEE CTS MASTER MARKUP	15. Process and Area Radiation Monitoring:					
	a. Fuel Storage Building Area Radiation Monitor (R-5)	D	24M	Q		
	b. Vapor Containment Process Radiation Monitors (R-11 and R-12)	D	24M	Q		
	c. Vapor Containment High Radiation Monitors (R-25 and R-26)	D	24M	Q		
	d. Wide Range Plant Vent Gas Process Radiation Monitor (R-27)	D	24M	Q		

Amendment No. 8, 38, 63, 68, 74, 93, 107, 123, 137, 140, 144, 148, 150, 154, 169

Add SR 3.3.1.11 and SR3.3.1.13 for Functions 17.a (P-6), 17 b (P-7), 17.c (P-8), 17.d (P-10) and 17.e (P-7 input) M.10

TABLE 4.1-1 (Sheet 2 of 6)

	Channel Description	Check	Calibrate	Test	Remarks	
SEE 3.3.1	8. 6.9 KV Voltage 6.9 KV Frequency	N.A. N.A.	18M 24M	Q Q	Reactor protection circuits only Reactor protection circuits only	
SEE 3.1.7	9. Analog Rod Position	S	24M	M		
T3.3.2-1, #6.b	10. Steam Generator Level	S SR 3.3.2.1	24M SR 3.3.2.7	Q SR 3.3.2.4		A.26
SEE ITS 3.3.3	11. Residual Heat Removal Pump Flow	N.A.	24M	N.A.		
	12. Boric Acid Tank Level	S	24M	N.A.	Bubbler tube rodded during calibration	
	13. Refueling Water Storage Tank Level a. Transmitter b. Indicating Switch	 W W	 18M 6M	 N.A. N.A.	 Low level alarm Low level alarm	
	14a. Containment Pressure - narrow range	S	24M	Q	High and High-High A.5 A.12 A.18	A.21
SEE 3.3.3	14b. Containment Pressure - wide range	M	18M	N.A.		
SEE CTS MASTER MARKUP	15. Process and Area Radiation Monitoring:				SR 3.3.2.4 SR 3.3.2.7 SR 3.3.2.1	
	a. Fuel Storage Building Area Radiation Monitor (R-5)	D	24M	Q		
	b. Vapor Containment Process Radiation Monitors (R-11 and R-12)	D	24M	Q		
	c. Vapor Containment High Radiation Monitors (R-25 and R-26)	D	24M	Q		
	d. Wide Range Plant Vent Gas Process Radiation Monitor (R-27)	D	24M	Q		

Amendment No. 8, 38, 65, 68, 74, 93, 107, 125, 137, 140, 144, 148, 150, 154, 169

T 3.3.2-1, #1.C A.5
" 2.C A.12
" 3.b.3 A.18
" 4.C A.21

ITS 3.3.2

SEE CTS MASTER MARKUP

31 days — L.2

SR 3.3.3.1

TABLE 4.1-1 (Sheet 2 of 6)

	Channel Description	Check	Calibrate	Test	Remarks
	8. 6.9 KV Voltage	N.A.	18M	Q	Reactor protection circuits only
	6.9 KV Frequency	N.A.	24M	Q	Reactor protection circuits only
	9. Analog Rod Position	S	24M	M	
T3.3.3-1, #13 #14	10. Steam Generator Level	S SR 3.3.3.1	24M SR 3.3.3.2	Q	SEE ITS 3.3.2 A.13
	11. Residual Heat Removal Pump Flow	N.A.	24M	N.A.	
	12. Boric Acid Tank Level	S	24M	N.A.	Bubbler tube rodded during ~~calibration~~
T3.3.3-1, #17	13. Refueling Water Storage Tank Level	LA.1	SR 3.3.3.2		
	a. Transmitter	W	18M	N.A.	Low level alarm
	b. Indicating Switch	W	6M	N.A.	Low level alarm A.16
	14a. Containment Pressure - narrow range	S	24M	Q	High and High-High
T3.3.3-1, #8	14b. Containment Pressure - wide range	M SR 3.3.3.1	18M SR 3.3.3.2	N.A.	A.8
	15. Process and Area Radiation Monitoring:				
	a. Fuel Storage Building Area Radiation Monitor (R-5)	D	24M	Q	
	b. Vapor Containment Process Radiation Monitors (R-11 and R-12)	D	24M	Q	
T3.3.3-1, #10	c. Vapor Containment High Radiation Monitors (R-25 and R-26)	D 31 days	24M	~~Q~~	SEE RELOCATED CTS L.2 A.10
	d. Wide Range Plant Vent Gas Process Radiation Monitor (R-27)	D	24M	Q	

Amendment No. 8, 38, 63, 68, 74, 93, 107, 125, 137, 140, 144, 148, 150, 154, 169

ITS 3.3.3

TABLE 4.1-1 (Sheet 2 of 6)

Channel Description	Check	Calibrate	Test	Remarks
8. 6.9 KV Voltage	N.A.	18M	Q	Reactor protection circuits only
6.9 KV Frequency	N.A.	24M	Q	Reactor protection circuits only
9. Analog Rod Position	S	24M	M	
10. Steam Generator Level	S	24M	Q	
11. Residual Heat Removal Pump Flow	N.A.	24M	N.A.	
12. Boric Acid Tank Level	S	24M	N.A.	Bubbler tube rodded during calibration
13. Refueling Water Storage Tank Level				
a. Transmitter	W	18M	N.A.	Low level alarm
b. Indicating Switch	W	6M	N.A.	Low level alarm
14a. Containment Pressure - narrow range	S	24M	Q	High and High-High
14b. Containment Pressure - wide range	M	18M	N.A.	
15. Process and Area Radiation Monitoring:				
a. Fuel Storage Building Area Radiation Monitor (R-5)	D	24M	Q	
b. Vapor Containment Process Radiation Monitors (R-11 and R-12)	D SR 3.3.6.1	24M SR 3.3.6.5	Q SR 3.3.6.3	
c. Vapor Containment High Radiation Monitors (R-25 and R-26)	D	24M	Q	
d. Wide Range Plant Vent Gas Process Radiation Monitor (R-27)	D	24M	Q	

SEE CTS MASTER MARK UP

SR 3.3.6.1
SR 3.3.6.3
SR 3.3.6.5

SEE CTS MASTER MARK UP

ITS 3.3.6

TABLE 4.1-1 (Sheet 2 of 6)

SEE CTS MASTER MARKUP

Channel Description	Check	Calibrate	Test	Remarks
8. 6.9 KV Voltage	N.A.	18M	Q	Reactor protection circuits only
6.9 KV Frequency	N.A.	24M	Q	Reactor protection circuits only
9. Analog Rod Position	S	24M	M	
10. Steam Generator Level	S	24M	Q	
11. Residual Heat Removal Pump Flow	N.A.	24M	N.A.	
12. Boric Acid Tank Level	S	24M	N.A.	Bubbler tube rodded during calibration
13. Refueling Water Storage Tank Level				
a. Transmitter	W	18M	N.A.	Low level alarm
b. Indicating Switch	W	6M	N.A.	Low level alarm
14a. Containment Pressure - narrow range	S	24M	Q	High and High-High
14b. Containment Pressure - wide range	M	18M	N.A.	
15. Process and Area Radiation Monitoring:	SR 3.3.8.1	SR 3.3.8.4	SR 3.3.8.2	Add SR 3.3.8.3 — M.1
a. Fuel Storage Building Area Radiation Monitor (R-5)	D	24M	Q	
b. Vapor Containment Process Radiation Monitors (R-11 and R-12)	D	24M	Q	
c. Vapor Containment High Radiation Monitors (R-25 and R-26)	D	24M	Q	
d. Wide Range Plant Vent Gas Process Radiation Monitor (R-27)	D	24M	Q	

SR 3.3.8.1
3.3.8.2
3.3.8.3
3.3.8.4

SEE CTS MASTER MARKUP

Amendment No. 8, 38, 63, 68, 74, 93, 107, 125, 137, 140, 144, 148, 150, 154, 169

ITS 3.3.8

Add SR 3.4.15.5

Add SR 3.4.15.3

M.6

TABLE 4.1-1 (Sheet 2 of 6)

SEE CTS MASTER MARKUP

Channel Description	Check	Calibrate	Test	Remarks
8. 6.9 KV Voltage	N.A.	18M	Q	Reactor protection circuits only
6.9 KV Frequency	N.A.	24M	Q	Reactor protection circuits only
9. Analog Rod Position	S	24M	M	
10. Steam Generator Level	S	24M	Q	
11. Residual Heat Removal Pump Flow	N.A.	24M	N.A.	
12. Boric Acid Tank Level	S	24M	N.A.	Bubbler tube rodded during calibration
13. Refueling Water Storage Tank Level				
a. Transmitter	W	18M	N.A.	Low level alarm
b. Indicating Switch	W	6M	N.A.	Low level alarm
14a. Containment Pressure - narrow range	S	24M	Q	High and High-High
14b. Containment Pressure - wide range	M	18M	N.A.	
15. Process and Area Radiation Monitoring:				
a. Fuel Storage Building Area Radiation Monitor (R-5)	D	24M	Q	
b. Vapor Containment Process Radiation Monitors (R-11 and R-12)	D 12 hours	24M	Q	
c. Vapor Containment High Radiation Monitors (R-25 and R-26)	D	24M	Q	
d. Wide Range Plant Vent Gas Process Radiation Monitor (R-27)	D	24M	Q	

SR 3.4.15.1
SR 3.4.15.2
SR 3.4.15.4

M.8

SEE CTS MASTER MARKUP

Amendment No. 8, 38, 63, 68, 74, 93, 107, 125, 137, 140, 144, 148, 150, 154, 169

SR 3.4.15.1 SR 3.4.15.4 SR 3.4.15.2

ITS 3.4.15

TABLE 4.1-1 (Sheet 2 of 6)

Channel Description	Check	Calibrate	Test	Remarks
8. 6.9 KV Voltage	N.A.	18M	Q	Reactor protection circuits only
6.9 KV Frequency	N.A.	24M	Q	Reactor protection circuits only
9. Analog Rod Position	S	24M	M	
10. Steam Generator Level	S	24M	Q	
11. Residual Heat Removal Pump Flow	N.A.	24M	N.A.	
12. Boric Acid Tank Level	S	24M	N.A.	Bubbler tube rodded during calibration
13. Refueling Water Storage Tank Level				
a. Transmitter	W	18M	N.A.	Low level alarm
b. Indicating Switch	W	6M	N.A.	Low level alarm
14a. Containment Pressure - narrow range	S	24M	Q	High and High-High
14b. Containment Pressure - wide range	M	18M	N.A.	
15. Process and Area Radiation Monitoring:				SEE ITS 3.3.8
SR 3.7.13.4 a. Fuel Storage Building Area Radiation Monitor (R-5)	D	24M	Q	
b. Vapor Containment Process Radiation Monitors (R-11 and R-12)	D	24M	Q	
c. Vapor Containment High Radiation Monitors (R-25 and R-26)	D	24M	Q	
d. Wide Range Plant Vent Gas Process Radiation Monitor (R-27)	D	24M	Q	

Amendment No. 8, 38, 65, 68, 74, 93, 107, 125, 137, 140, 144, 148, 150, 154, 169

ITS 3.7.13

A.1

TABLE 4.1-1 (Sheet 2 of 6)

	Channel Description	Check	Calibrate	Test	Remarks
SEE CTS MASTER MARKUP	8. 6.9 KV Voltage	N.A.	18M	Q	Reactor protection circuits only
	6.9 KV Frequency	N.A.	24M	Q	Reactor protection circuits only
	9. Analog Rod Position	S	24M	M	
	10. Steam Generator Level	S	24M	Q	
	11. Residual Heat Removal Pump Flow	N.A.	24M	N.A.	
	12. Boric Acid Tank Level	S	24M	N.A.	Bubbler tube rodded during calibration
	13. Refueling Water Storage Tank Level				
	a. Transmitter	W	18M	N.A.	Low level alarm
	b. Indicating Switch	W	6M	N.A.	Low level alarm
	14a. Containment Pressure - narrow range	S	24M	Q	High and High-High
	14b. Containment Pressure - wide range	M	18M	N.A.	
	15. Process and Area Radiation Monitoring:				
	a. Fuel Storage Building Area Radiation Monitor (R-5)	D	24M	Q	
SEE ITS 3.3.6	b. Vapor Containment Process Radiation Monitors (R-11 and R-12)	D	24M	Q	
SEE CTS MASTER	c. Vapor Containment High Radiation Monitors (R-25 and R-26)	D	24M	Q	
	d. Wide Range Plant Vent Gas Process Radiation Monitor (R-27)	D	24M	Q	

ITS 3.9.3

SEE CTS MASTER MARKUP

TABLE 4.1-1 (Sheet 2 of 6)

Channel Description	Check	Calibrate	Test	Remarks
8. 6.9 KV Voltage 6.9 KV Frequency	N.A. N.A.	18M 24M	Q Q	Reactor protection circuits only Reactor protection circuits only
9. Analog Rod Position	S	24M	M	
10. Steam Generator Level	S	24M	Q	
11. Residual Heat Removal Pump Flow	N.A.	24M	N.A.	
12. Boric Acid Tank Level	S	24M	N.A.	Bubbler tube rodded during calibration
13. Refueling Water Storage Tank Level a. Transmitter b. Indicating Switch	 W W	 18M 6M	 N.A. N.A.	 Low level alarm Low level alarm
14a. Containment Pressure - narrow range 14b. Containment Pressure - wide range	S M	24M 18M	Q N.A.	High and High-High
15. Process and Area Radiation Monitoring:				
SEE ITS 3.3.8 a. Fuel Storage Building Area Radiation Monitor (R-5)	D	24M	Q	
SEE ITS 3.3.6 b. Vapor Containment Process Radiation Monitors (R-11 and R-12)	D	24M	Q	
c. ~~Vapor Containment High Radiation Monitors (R-25 and R-26)~~	~~D~~	24M	~~Q~~	R.8
d. ~~Wide Range Plant Vent Gas Process Radiation Monitor (R-27)~~	~~D~~	~~24M~~	Q	

Amendment No. 8, 38, 65, 68, 74, 93, 107, 125, 137, 140, 144, 148, 150, 154, 169

Relocated Item (R-8)

ITS 3.3.1

TABLE 4.1-1 (Sheet 3 of 6)

	Channel Description	Check	Calibrate	Test	Remarks	
SEE CTS MASTER MARKUP	e. Main Steam Lines Process Radiation Monitors (R-62A, R-62B, R-62C, and R-62D)	D	24M	Q		
	f. Gross Failed Fuel Detectors (R-63A and R-63B)	D	24M	Q		
	16. Containment Water Level Monitoring System:					
	a. Containment Sump	N.A.	24M	N.A.	Narrow Range, Analog	
	b. Recirculation Sump	N.A.	24M	N.A.	Narrow Range, Analog	
	c. Containment Water Level	N.A.	24M	N.A.	Wide Range	
	17. Accumulator Level and Pressure	S	24M	N.A.		
	18. Steam Line Pressure	S	24M	Q		
T3.3.1-1, #17e	19. Turbine First Stage Pressure	S	24M	Q		A.30
T3.3.1-1, #20	20a. Reactor Trip Relay Logic	N.A.	N.A.	TM 3.3.1.5		A.25
SEE 3.3.2	20b. ESF Actuation Relay Logic	N.A.	N.A.	TM		
T3.3.1-1, #15	21. Turbine Trip Low Auto Stop Oil Pressure	N.A.	24M SR 3.3.1.10	N.A.	Add SR 3.3.1.15 M.8	A.21
	~~22. DELETED~~	~~DELETED~~	~~DELETED~~	~~DELETED~~		
SEE CTS MASTER MARKUP	23. Temperature Sensor in Auxiliary Boiler Feedwater Pump Building	N.A.	N.A.	18M		
	24. Temperature Sensors in Primary Auxiliary Building					
	a. Piping Penetration Area	N.A.	N.A.	24M		
	b. Mini-Containment Area	N.A.	N.A.	24M		
	c. Steam Generator Blowdown Heat Exchanger Room	N.A.	N.A.	24M		

T 3.3.2-1, #1.e — A.7
#1.g — A.9

TABLE 4.1-1 (Sheet 3 of 6)

Channel Description	Check	Calibrate	Test	Remarks
e. Main Steam Lines Process Radiation Monitors (R-62A, R-62B, R-62C, and R-62D)	D	24M	Q	
f. Gross Failed Fuel Detectors (R-63A and R-63B)	D	24M	Q	
16. Containment Water Level Monitoring System:				
a. Containment Sump	N.A.	24M	N.A.	Narrow Range, Analog
b. Recirculation Sump	N.A.	24M	N.A.	Narrow Range, Analog
c. Containment Water Level	N.A.	24M	N.A.	Wide Range
17. Accumulator Level and Pressure	S	24M	N.A.	
18. Steam Line Pressure	SR 3.3.2.1 S	SR 3.3.2.7 24M	SR 3.3.2.4 Q	A.7 A.9
19. Turbine First Stage Pressure	S	24M	Q	A.8 A.9 A.22 A.23
20a. Reactor Trip Relay Logic	N.A.	N.A.	TM	
20b. ESF Actuation Relay Logic	N.A.	N.A.	TM	A.27 A.24 A.4 A.11 A.14 A.17 A.20 A.25 A.15
21. Turbine Trip Low Auto Stop Oil Pressure	N.A.	24M	N.A.	SR 3.3.2.2 SR 3.3.2.3 SR 3.3.2.5 → 24 months
22. DELETED	DELETED	DELETED	DELETED	
23. Temperature Sensor in Auxiliary Boiler Feedwater Pump Building	N.A.	N.A.	18M	
24. Temperature Sensors in Primary Auxiliary Building				
a. Piping Penetration Area	N.A.	N.A.	24M	
b. Mini-Containment Area	N.A.	N.A.	24M	
c. Steam Generator Blowdown Heat Exchanger Room	N.A.	N.A.	24M	

SEE CTS MASTER MARKUP

T 3.3.2-1, Note c

SEE 3.3.1

SEE CTS MASTER MARKUP

T 3.3.2-1, #1.b, 2.b, 3.a.(2), 3.b.(2), 4.b, c.a AND 3.a.3, 5, 6.c

31 days   L.Z

SR 3.3.3.1   SR 3.3.3.2

TABLE 4.1-1 (Sheet 3 of 6)

	Channel Description	Check	Calibrate	Test	Remarks	
T3.3.3-1, #18	e. Main Steam Lines Process Radiation Monitors (R-62A, R-62B, R-62C, and R-62D)	~~D~~ 31 days L.2	24M	Q	LA.3	A.18
T3.3.3-1, #23	f. Gross Failed Fuel Detectors (R-63A and R-63B)	D 31 days L.2	24M	Q	LA.3	A.19
T3.3.3-1, #6 #7	16. Containment Water Level Monitoring System:				LA.1	A.7
	~~a. Containment Sump~~	~~N.A.~~	~~24M~~	~~N.A.~~	~~Narrow Range, Analog~~	
	b. Recirculation Sump	N.A.	24M	N.A.	Narrow Range, Analog	
	c. Containment Water Level	N.A. M.11	24M	N.A.	Wide Range	
SEE 3.5.1	17. Accumulator Level and Pressure	S	24M	N.A.		
	18. Steam Line Pressure L2	~~S~~ 31 days	24M	Q	SEE ITS 3.3.2	
SEE ITS 3.3.1 ITS 3.3.2	19. Turbine First Stage Pressure	S	24M	Q		
	20a. Reactor Trip Relay Logic	N.A.	N.A.	TM		
	20b. ESF Actuation Relay Logic	N.A.	N.A.	TM		
	21. Turbine Trip Low Auto Stop Oil Pressure	N.A.	24M	N.A.		
	22. DELETED	DELETED	DELETED	DELETED		
	~~23. Temperature Sensor in Auxiliary Boiler Feedwater Pump Building~~	~~N.A.~~	~~N.A.~~	~~18M~~	LA.1	
	~~24. Temperature Sensors in Primary Auxiliary Building~~					
	~~a. Piping Penetration Area~~	~~N.A.~~	~~N.A.~~	~~24M~~		
	~~b. Mini-Containment Area~~	~~N.A.~~	~~N.A.~~	~~24M~~		
	~~c. Steam Generator Blowdown Heat Exchanger Room~~	~~N.A.~~	~~N.A.~~	~~24M~~		

ITS 3.3.3

SEE CTS MASTER MARKUP

TABLE 4.1-1 (Sheet 3 of 6)

Channel Description	Check	Calibrate	Test	Remarks
e. Main Steam Lines Process Radiation Monitors (R-62A, R-62B, R-62C, and R-62D)	D	24M	Q	
f. Gross Failed Fuel Detectors (R-63A and R-63B)	D	24M	Q	
16. Containment Water Level Monitoring System:				
a. Containment Sump	N.A.	24M	N.A.	Narrow Range, Analog
b. Recirculation Sump	N.A.	24M	N.A.	Narrow Range, Analog
c. Containment Water Level	N.A.	24M	N.A.	Wide Range
17. Accumulator Level and Pressure	S	24M	N.A.	
18. Steam Line Pressure	S	24M	Q	
19. Turbine First Stage Pressure	S	24M	Q	
~~20a. Reactor Trip Relay Logic~~	~~N.A.~~	~~N.A.~~	~~TM~~	
20b. ESF Actuation Relay Logic	N.A.	N.A.	TM	
~~21. Turbine Trip Low Auto Stop Oil Pressure~~	~~N.A.~~	~~24M~~	~~N.A.~~	
22. DELETED	DELETED	DELETED	DELETED	
23. Temperature Sensor in Auxiliary Boiler Feedwater Pump Building	N.A.	N.A.	18M	
24. Temperature Sensors in Primary Auxiliary Building				
a. Piping Penetration Area	N.A.	N.A.	24M	
b. Mini-Containment Area	N.A.	N.A.	24M	
c. Steam Generator Blowdown Heat Exchanger Room	N.A.	N.A.	24M	

T 3.3.6-1, #3

SEE CTS MASTER MARKUP

ITS 3.3.6

Add SR 3.3.7.1
SR 3.3.7.2 (M.2)

TABLE 4.1-1 (Sheet 3 of 6)

SEE CTS MASTER MARKUP

Channel Description	Check	Calibrate	Test	Remarks
e. Main Steam Lines Process Radiation Monitors (R-62A, R-62B, R-62C, and R-62D)	D	24M	Q	
f. Gross Failed Fuel Detectors (R-63A and R-63B)	D	24M	Q	
16. Containment Water Level Monitoring System:				
a. Containment Sump	N.A.	24M	N.A.	Narrow Range, Analog
b. Recirculation Sump	N.A.	24M	N.A.	Narrow Range, Analog
c. Containment Water Level	N.A.	24M	N.A.	Wide Range
17. Accumulator Level and Pressure	S	24M	N.A.	
18. Steam Line Pressure	S	24M	Q	
19. Turbine First Stage Pressure	S	24M	Q	
20a. Reactor Trip Relay Logic	N.A.	N.A.	TM	
20b. ESF Actuation Relay Logic	N.A.	N.A.	TM	
21. Turbine Trip Low Auto Stop Oil Pressure	N.A.	24M	N.A.	
22. DELETED	DELETED	DELETED	DELETED	
23. Temperature Sensor in Auxiliary Boiler Feedwater Pump Building	N.A.	N.A.	18M	
24. Temperature Sensors in Primary Auxiliary Building				
a. Piping Penetration Area	N.A.	N.A.	24M	
b. Mini-Containment Area	N.A.	N.A.	24M	
c. Steam Generator Blowdown Heat Exchanger Room	N.A.	N.A.	24M	

SEE CTS MASTER MARKUP

ITS 3.3.7

TABLE 4.1-1 (Sheet 3 of 6)

Channel Description	Check	Calibrate	Test	Remarks
e. Main Steam Lines Process Radiation Monitors (R-62A, R-62B, R-62C, and R-62D)	D	24M	Q	
f. Gross Failed Fuel Detectors (R-63A and R-63B)	D	24M	Q	
16. Containment Water Level Monitoring System:				
a. Containment Sump	N.A.	24M	N.A.	Narrow Range, Analog
b. Recirculation Sump	N.A.	24M	N.A.	Narrow Range, Analog
c. Containment Water Level	N.A.	24M	N.A.	Wide Range
SR 3.5.1.2 SR 3.5.1.3 17. Accumulator Level and Pressure	~~S~~ 12 hours	18M***	N.A.	A.3 LA.1 Changed to 24 months by TSCR 98-043
18. Steam Line Pressure	S	24M	Q	
19. Turbine First Stage Pressure	S	24M	Q	
20a. Reactor Trip Relay Logic	N.A.	N.A.	TM	
20b. ESF Actuation Relay Logic	N.A.	N.A.	TM	
21. Turbine Trip Low Auto Stop Oil Pressure	N.A.	24M	N.A.	
22. DELETED	DELETED	DELETED	DELETED	
23. Temperature Sensor in Auxiliary Boiler Feedwater Pump Building	N.A.	N.A.	18M	
24. Temperature Sensors in Primary Auxiliary Building				
a. Piping Penetration Area	N.A.	N.A.	24M	
b. Mini-Containment Area	N.A.	N.A.	24M	
c. Steam Generator Blowdown Heat Exchanger Room	N.A.	N.A.	24M	

TABLE 4.1-1 (Sheet 4 of 6)

	Channel Description	Check	Calibrate	Test	Remarks	
SEE CTS MASTER MARKUP	25. Level Sensors in Turbine Building	N.A.	N.A.	24M		
	26. Volume Control Tank Level	N.A.	24M	N.A.		
	27. Boric Acid Makeup Flow Channel	N.A.	24M	N.A.		
T3.3.2-1,	28. Auxiliary Feedwater:	SR 3.3.2.1	SR 3.3.2.7	SR 3.3.2.4	SR 3.3.2.6	
#6.b	a. Steam Generator Level	S	24M	Q	Low-Low	A.26
6.d	b. Undervoltage	N.A.	24M	24M		A.28
6.e	c. Main Feedwater Pump Trip	N.A.	N.A.	24M		A.29
SEE CTS MASTER MARKUP	29. Reactor Coolant System Subcooling Margin Monitor	D	24M	N.A.		
	30. PORV Position Indicator	N.A.	N.A.	24M	Limit Switch	
	31. PORV Position Indicator	D	24M	24M	Acoustic Monitor	
	32. Safety Valve Position Indicator	D	24M	24M	Acoustic Monitor	
	33. Auxiliary Feedwater Flow Rate	N.A.	18M	N.A.		
	34. Plant Effluent Radioiodine/ Particulate Sampling	N.A.	N.A.	18M	Sample line common with monitor R-13	
	35. Loss of Power					
	a. 480v Bus Undervoltage Relay	N.A.	24M	M		
	b. 480v Bus Degraded Voltage Relay	N.A.	18M	M		
	c. 480v Safeguards Bus Undervoltage Alarm	N.A.	24M	M		
	36. Containment Hydrogen Monitors	D	Q	M		

ITS 3.3.2

SEE CTS MASTER MARKUP

TABLE 4.1-1 (Sheet 4 of 6)

	Channel Description	Check	Calibrate	Test	Remarks	
	25. Level Sensors in Turbine Building	N.A.	N.A.	24M		
	26. Volume Control Tank Level	N.A.	24M	N.A.		
	27. Boric Acid Makeup Flow Channel	N.A.	24M	N.A.		
	28. Auxiliary Feedwater: a. Steam Generator Level b. Undervoltage c. Main Feedwater Pump Trip	 S N.A. N.A.	 24M 24M N.A.	 Q 24M 24M	 Low-Low	
T3.3.1-1 # 24	29. Reactor Coolant System Subcooling Margin Monitor	D 31 days SR 3.3.3.1	24M SR 3.3.3.2	N.A.	L.2	A.20
	30. PORV Position Indicator	N.A.	N.A.	24M	Limit Switch	LA.1
	31. PORV Position Indicator	D	24M	24M	Acoustic Monitor	
	32. Safety Valve Position Indicator	D	24M	24M	Acoustic Monitor	
	33. Auxiliary Feedwater Flow Rate	N.A.	18M	N.A.		
	34. Plant Effluent Radioiodine/ Particulate Sampling	N.A.	N.A.	18M	Sample line common with monitor R-13	
	35. Loss of Power a. 480v Bus Undervoltage Relay b. 480v Bus Degraded Voltage Relay c. 480v Safeguards Bus Undervoltage Alarm	 N.A. N.A. N.A.	 24M 18M 24M	 M M M		
T3.3.3-1 #11	36. Containment Hydrogen Monitors	D 31 days	Q	M	LA.3 L.2	A.11

SR 3.3.3.1 SR 3.3.3.2

Amendment No. 38, 44, 54, 65, 67, 74, 93, 125, 136, 137, 142, 144, 150, 168, 169, TSCR 98-043

TABLE 4.1-1 (Sheet 4 of 6)

Channel Description	Check	Calibrate	Test	Remarks
25. Level Sensors in Turbine Building	N.A.	N.A.	24M	
26. Volume Control Tank Level	N.A.	24M	N.A.	
27. Boric Acid Makeup Flow Channel	N.A.	24M	N.A.	
28. Auxiliary Feedwater:				
a. Steam Generator Level	S	24M	Q	Low-Low
b. Undervoltage	N.A.	24M	24M	
c. Main Feedwater Pump Trip	N.A.	N.A.	24M	
29. Reactor Coolant System Subcooling Margin Monitor	D	24M	N.A.	
30. PORV Position Indicator	N.A.	N.A.	24M	Limit Switch
31. PORV Position Indicator	D	24M	24M	Acoustic Monitor
32. Safety Valve Position Indicator	D	24M	24M	Acoustic Monitor
33. Auxiliary Feedwater Flow Rate	N.A.	18M	N.A.	
34. Plant Effluent Radioiodine/ Particulate Sampling	N.A.	N.A.	18M	Sample line common with monitor R-13
35. Loss of Power		SR 3.3.5.2	SR 3.3.5.1	
SR 3.3.5.2 a. 480v Bus Undervoltage Relay	N.A.	24M	M	
SR 3.3.5.1 b. 480v Bus Degraded Voltage Relay	N.A.	18M	M	
c. 480v Safeguards Bus Undervoltage Alarm	N.A.	24M	M	LA3
36. Containment Hydrogen Monitors	D	Q	M	

ITS 3.3.5

Amendment No. 38, 44, 54, 65, 67, 74, 93, 125, 136, 137, 142, 144, 150, 168, 169, TSCR 98-043

SEE CTS
MASTER MARKUP

TABLE 4.1-1 (Sheet 4 of 6)

Channel Description	Check	Calibrate	Test	Remarks
25. Level Sensors in Turbine Building	N.A.	N.A.	24M	
26. Volume Control Tank Level	N.A.	24M	N.A.	
27. Boric Acid Makeup Flow Channel	N.A.	24M	N.A.	
28. Auxiliary Feedwater:				
a. Steam Generator Level	S	24M	Q	Low-Low
b. Undervoltage	N.A.	24M	24M	
c. Main Feedwater Pump Trip	N.A.	N.A.	24M	
29. Reactor Coolant System Subcooling Margin Monitor	D	18M****	N.A.	
30. PORV Position Indicator	N.A.	N.A.	24M	Limit Switch
31. PORV Position Indicator	D	24M	24M	Acoustic Monitor
32. Safety Valve Position Indicator	D	24M	24M	Acoustic Monitor
33. Auxiliary Feedwater Flow Rate	N.A.	18M	N.A.	
R.8 34. Plant Effluent Radioiodine/Particulate Sampling	N.A.	N.A.	18M	Sample line common with monitor R-13 R8
35. Loss of Power				
a. 480v Bus Undervoltage Relay	N.A.	24M	M	
b. 480v Bus Degraded Voltage Relay	N.A.	18M	M	
c. 480v Safeguards Bus Undervoltage Alarm	N.A.	24M	M	
36. Containment Hydrogen Monitors	D	Q	M	

Amendment No. 38, 44, 54, 65, 67, 74, 93, 128, 136, 137, 142, 144, 150, 168, 169

Relocated Item (R-8)

Add T.3.3.1-1, #16, RPS input to ESFAS (A.22)

Add T3.3.1-1, #10a, #10b RCP Breaker Position (A.15) (A.16)

TABLE 4.1-1 (Sheet 5 of 6)

	Channel Description	Check	Calibrate	Test	Remarks	
SEE ITS 3.3.3	37. Core Exit Thermocouples	D	24M	N.A.		
SEE ITS 3.4.12	38. Overpressure Protection System (OPS)	D	18M (1)	18M	1) Calibration frequency for OPS sensors (RCS pressure and temperature) is 24 months	
T3.3.1-1, #18	~~39.~~ Reactor Trip Breakers	N.A.	N.A.	~~TM(1)~~ SR3.3.1.4 24M(2) SR3.3.1.14	1) Independent operation of under-voltage and shunt trip attachments ~~2) Independent operation of under-voltage and shunt trip from Control Room manual push-button~~	A.23 A.24
#19	40. Reactor Trip Bypass Breakers	N.A.	N.A.	(1) Note to SR3.3.1.4 24M(2) SR3.3.1.14	~~1) Manual shunt trip prior to each use~~ ~~2) Independent operation of under-voltage and shunt trip from Control Room manual push-button~~	
T3.3.1-1, #1				24M(3) SR 3.3.1.14	3) Automatic undervoltage trip (A.15) (A.16)	A.3
SEE ITS 3.3.3	41. Reactor Vessel Level Indication System (RVLIS)	D	24M	N.A.		
SEE ITS 3.6.5	42. Ambient Temperature Sensors Within the Containment Building	D	24M	N.A.		
SEE ITS 3.7.10	43. River Water Temperature # (installed)	S	18M	N.A.	1) Check against installed instrumentation or another portable device	
	44. River Water Temperature # (portable)	S (1)	Q (2)	N.A.	2) Calibrate within 30 days prior to use and quarterly thereafter	
T3.3.1-1, #14	45. Steam Line Flow	~~S~~ SR3.3.1.1	~~24M~~ SR3.3.1.10	~~Q~~ SR3.3.1.7	Engineered Safety Features circuits only	A.20

ITS 3.3.1

TABLE 4.1-1 (Sheet 5 of 6)

Channel Description	Check	Calibrate	Test	Remarks
37. Core Exit Thermocouples	D	24M	N.A.	
38. Overpressure Protection System (OPS)	D	18M (1)	18M	1) Calibration frequency for OPS sensors (RCS pressure and temperature) is 24 months
39. Reactor Trip Breakers	N.A.	N.A.	TM(1)	1) Independent operation of under-voltage and shunt trip attachments
			24M(2)	2) Independent operation of under-voltage and shunt trip from Control Room manual push-button
40. Reactor Trip Bypass Breakers	N.A.	N.A.	(1)	1) Manual shunt trip prior to each use
			24M(2)	2) Independent operation of under-voltage and shunt trip from Control Room manual push-button
			24M(3)	3) Automatic undervoltage trip
41. Reactor Vessel Level Indication System (RVLIS)	D	24M	N.A.	
42. Ambient Temperature Sensors Within the Containment Building	D	24M	N.A.	
43. River Water Temperature # (installed)	S	18M	N.A.	1) Check against installed instrumentation or another portable device
44. River Water Temperature # (portable)	S (1)	Q (2)	N.A.	2) Calibrate within 30 days prior to use and quarterly thereafter
45. Steam Line Flow	S SR 3.3.2.1	24M SR 3.3.2.7	Q SR 3.3.2.4	Engineered Safety Features circuits only

SEE CTS MASTER MARKUP

Amendment No. 38, 54, 63, 74, 78, 93, 98, 107, 125, 126, 137, 140, 142, 164, 169,

TSCR 98-043

A.8 A.9 A.22 A.23

T3.3.2-1, 1.f and 4.d
1.g 4.e

ITS 3.3.2

TABLE 4.1-1 (Sheet 5 of 6)

	Channel Description	Check L.2	Calibrate	Test	Remarks	
T3.3.3-1 #18,19,20,21	37. Core Exit Thermocouples	D 31 day SR 3.3.3.1	24M SR3.3.3.2	N.A.	A.17	1
SEE CTS MASTER MARKUP	38. Overpressure Protection System (OPS)	D	18M (1)	18M	1) Calibration frequency for OPS sensors (RCS pressure and temperature) is 24 months	
	39. Reactor Trip Breakers	N.A.	N.A.	TM(1)	1) Independent operation of under-voltage and shunt trip attachments	
				24M(2)	2) Independent operation of under-voltage and shunt trip from Control Room manual push-button	
	40. Reactor Trip Bypass Breakers	N.A.	N.A.	(1)	1) Manual shunt trip prior to each use	
				24M(2)	2) Independent operation of under-voltage and shunt trip from Control Room manual push-button	
				24M(3)	3) Automatic undervoltage trip	
SR3.3.3.1 SR3.3.3.2	41. Reactor Vessel Level Indication System (RVLIS)	D 31 day SR3.3.3.1	24M SR3.3.3.2	N.A.	L.2	A.6
	42. Ambient Temperature Sensors Within the Containment Building	D	24M	N.A.		
	43. River Water Temperature # (installed)	S	18M	N.A.	1) Check against installed instrumentation or another portable device	
	44. River Water Temperature # (portable)	S (1)	Q (2)	N.A.	2) Calibrate within 30 days prior to use and quarterly thereafter	
	45. Steam Line Flow	S	24M	Q	Engineered Safety Features circuits only	

ITS 3.3.3

(A.10)

add Note to SR 3.4.12.6 — (L.1)

TABLE 4.1-1 (Sheet 5 of 6)

	Channel Description	Check	Calibrate	Test	Remarks
SEE ITS 3.3.3	37. Core Exit Thermocouples	D	N.A.	18M	
SR 3.4.12.4 SR 3.4.12.6	38. Overpressure Protection System (OPS)	D 24 hours SR 3.4.12.4 & Note	18M (1) SR 3.4.12.7a	24M SR 3.4.12.6	1) Calibration frequency for OPS sensors (RCS pressure and temperature) is 24 months. SR 3.4.12.7.b.
See ITS Master Markup	39. Reactor Trip Breakers	N.A.	N.A.	TM(1)	1) Independent operation of under-voltage and shunt trip attachments
				24M(2)	2) Independent operation of under-voltage and shunt trip from Control Room manual push-button
	40. Reactor Trip Bypass Breakers	N.A.	N.A.	(1)	1) Manual shunt trip prior to each use
				24M(2)	2) Independent operation of under-voltage and shunt trip from Control Room manual push-button
				24M(3)	3) Automatic undervoltage trip
	41. Reactor Vessel Level Indication System (RVLIS)	D	18M*****	N.A.	
	42. Ambient Temperature Sensors Within the Containment Building	D	24M	N.A.	
	43. River Water Temperature # (installed)	S	18M	N.A.	
	44. River Water Temperature # (portable)	S (1)	Q (2)	N.A.	1) Check against installed instrumentation or another portable device. 2) Calibrate within 30 days prior to use and quarterly thereafter.
	45. Steam Line Flow	S	24M	Q	Engineered Safety Features circuits only

TSCR 98-043 not shown. No impact on ITS 3.4.12

TABLE 4.1-1 (Sheet 5 of 6)

SEE CTS MASTER MARKUP

Channel Description	Check	Calibrate	Test	Remarks
37. Core Exit Thermocouples	D	24M	N.A.	
38. Overpressure Protection System (OPS)	D	18M (1)	18M	1) Calibration frequency for OPS sensors (RCS pressure and temperature) is 24 months
39. Reactor Trip Breakers	N.A.	N.A.	TM(1)	1) Independent operation of undervoltage and shunt trip attachments
			24M(2)	2) Independent operation of undervoltage and shunt trip from Control Room manual push-button
40. Reactor Trip Bypass Breakers	N.A.	N.A.	(1)	1) Manual shunt trip prior to each use
			24M(2)	2) Independent operation of undervoltage and shunt trip from Control Room manual push-button
			24M(3)	3) Automatic undervoltage trip
41. Reactor Vessel Level Indication System (RVLIS)	D	24M	N.A.	
42. ~~Ambient Temperature Sensors Within the Containment Building~~	~~D~~	~~24M~~	~~N.A.~~	
43. River Water Temperature # (installed)	S	18M	N.A.	1) Check against installed instrumentation or another portable device
44. River Water Temperature # (portable)	S (1)	Q (2)	N.A.	2) Calibrate within 30 days prior to use and quarterly thereafter
45. Steam Line Flow	S	24M	Q	Engineered Safety Features circuits only

LCO 3.6.5

LA.3

SEE CTS MASTER MARKUP

ITS 3.6.5

TABLE 4.1-1 (Sheet 5 of 6)

SEE CTS MASTER MARKUP

Channel Description	Check	Calibrate	Test	Remarks
37. Core Exit Thermocouples	D	24M	N.A.	
38. Overpressure Protection System (OPS)	D	18M (1)	18M	1) Calibration frequency for OPS sensors (RCS pressure and temperature) is 24 months
39. Reactor Trip Breakers	N.A.	N.A.	TM(1)	1) Independent operation of under-voltage and shunt trip attachments
			24M(2)	2) Independent operation of under-voltage and shunt trip from Control Room manual push-button
40. Reactor Trip Bypass Breakers	N.A.	N.A.	(1)	1) Manual shunt trip prior to each use
			24M(2)	2) Independent operation of under-voltage and shunt trip from Control Room manual push-button
			24M(3)	3) Automatic undervoltage trip
41. Reactor Vessel Level Indication System (RVLIS)	D	24M	N.A.	
42. Ambient Temperature Sensors Within the Containment Building	D	24M	N.A.	
SR 3.7.10.1 ~~43. River Water Temperature # (installed)~~	~~S~~	~~18M~~	~~N.A.~~	~~1) Check against installed instrumentation or another portable device~~ LA.1
~~44. River Water Temperature # (portable)~~	~~S (1)~~	~~Q (2)~~	~~N.A.~~	~~2) Calibrate within 30 days prior to use and quarterly thereafter~~
45. Steam Line Flow	S	24M	Q	Engineered Safety Features circuits only

ITS 3.7.10

Table Notation

SEE ITS 3.0

*	By means of the movable incore detector system
**	Quarterly when reactor power is below the setpoint and prior to each startup if not done previous month.
***	~~This surveillance requirement may be extended on a one time basis to no later than April 26, 1997.~~
****	~~This surveillance requirement may be extended on a one time basis to no later than May 12, 1997.~~
*****	~~This surveillance requirement may be extended on a one time basis to no later than May 14, 1997.~~
#	These requirements are applicable when specification 3.3.F.5 is in effect only.
##	The "each shift" frequency also requires verification that the DNB parameters (Reactor Coolant Temperature, Reactor Coolant Flow, and Pressurizer Pressure) are within the limits of Technical Specification 3.1.H.

TSCR 98-043

SEE ITS 3.4.1

A.17

~~S - Each Shift (i.e., at least once per 12 hours)~~
~~W - Weekly~~
~~P - Prior to each startup if not done previous week~~
~~M - Monthly~~
~~NA - Not Applicable~~
~~Q - Quarterly~~
~~D - Daily~~
~~18M - At least once per 18 months~~
~~TM - At least every two months on a staggered test basis (i.e., one train per month)~~
~~24M - At least once per 24 months~~
~~6M - At least once per 6 months~~

TABLE 4.1-1 (Sheet 6 of 6)

Table Notation

LA.2

	*	~~By means of the movable incore detector system~~
T3.3.1-1, #2.b SR 3.3.1.8, Freq	**	Quarterly when reactor power is below the setpoint and prior to each startup if not done previous ~~month~~ 92 days
SEE ITS 3.7.10	***	~~This surveillance requirement may be extended on a one time basis to no later than April 26, 1997.~~
	****	~~This surveillance requirement may be extended on a one time basis to no later than May 12, 1997.~~
	*****	~~This surveillance requirement may be extended on a one time basis to no later than May 14, 1997.~~
	#	These requirements are applicable when specification 3.3.F.5 is in effect only.
SEE ITS 3.4.1	##	The "each shift" frequency also requires verification that the DNB parameters (Reactor Coolant Temperature, Reactor Coolant Flow, and Pressurizer Pressure) are within the limits of Technical Specification 3.1.H.

A.?
L.?
TS 98

T3.3.1-1, #3 #4

A.6
A.7

SEE ITS 1.0

S	-	Each Shift (i.e., at least once per 12 hours)
W	-	Weekly
P	-	Prior to each startup if not done previous week
M	-	Monthly
NA	-	Not Applicable
Q	-	Quarterly
D	-	Daily
18M	-	At least once per 18 months
TM	-	At least every two months on a staggered test basis (i.e., one train per month)
24M	-	At least once per 24 months
6M	-	At least once per 6 months

TSCR 98-043

Deleted by TSCR 98-043

Table Notation

* By means of the movable incore detector system

** Quarterly when reactor power is below the setpoint and prior to each startup if not done previous month.

~~*** This surveillance requirement may be extended on a one time basis to no later than April 26, 1997.~~

~~**** This surveillance requirement may be extended on a one time basis to no later than May 12, 1997.~~

~~***** This surveillance requirement may be extended on a one time basis to no later than May 14, 1997.~~

\# These requirements are applicable when specification 3.3.F.5 is in effect only.

\#\# The "each shift" frequency also requires verification that the DNB parameters (Reactor Coolant Temperature, Reactor Coolant Flow, and Pressurizer Pressure) are within the limits of Technical Specification 3.1.H.

SR 3.4.1.1
SR 3.4.1.2
SR 3.4.1.3

S - Each Shift (i.e., at least once per 12 hours)
W - Weekly
P - Prior to each startup if not done previous week
M - Monthly
NA - Not Applicable
Q - Quarterly
D - Daily
18M - At least once per 18 months
TM - At least every two months on a staggered test basis (i.e., one train per month)
24M - At least once per 24 months
6M - At least once per 6 months

Deleted by TSCR 98-043

Table Notation

* By means of the movable incore detector system

** Quarterly when reactor power is below the setpoint and prior to each startup if not done previous month.

~~*** This surveillance requirement may be extended on a one time basis to no later than April 26, 1997.~~

~~**** This surveillance requirement may be extended on a one time basis to no later than May 12, 1997.~~

~~***** This surveillance requirement may be extended on a one time basis to no later than May 14, 1997.~~

\# These requirements are applicable when specification 3.3.F.5 is in effect only.

\#\# The "each shift" frequency also requires verification that the DNB parameters (Reactor Coolant Temperature, Reactor Coolant Flow, and Pressurizer Pressure) are within the limits of Technical Specification 3.1.H.

S - Each Shift (i.e., at least once per 12 hours)
W - Weekly
P - Prior to each startup if not done previous week
M - Monthly
NA - Not Applicable
Q - Quarterly
D - Daily
18M - At least once per 18 months
TM - At least every two months on a staggered test basis (i.e., one train per month)
24M - At least once per 24 months
6M - At least once per 6 months

TSCR 98-043

 ITS 3.7.10

Table Notation

SEE CTS MASTER MARKUP

*	By means of the movable incore detector system
**	Quarterly when reactor power is below the setpoint and prior to each startup if not done previous month.

SR 3.7.10.1

#	These ~~requirements are applicable when specification 3.3.F.5 is in effect~~ only. LA.1

SEE CTS MASTER MARKUP

##	The "each shift" frequency also requires verification that the DNB parameters (Reactor Coolant Temperature, Reactor Coolant Flow, and Pressurizer Pressure) are within the limits of Technical Specification 3.1.H.
S	- Each Shift
W	- Weekly
P	- Prior to each startup if not done previous week
M	- Monthly
NA	- Not Applicable
Q	- Quarterly
D	- Daily
18M	- At least once per 18 months
TM	- At least every two months on a staggered test basis (i.e., one train per month)
24M	- At least once per 24 months
6M	- At least once per 6 months

TABLE 4.1-2 (Sheet 1 of 2)

SEE RELOCATED

SEE CTS MASTER MARKUP

FREQUENCIES FOR SAMPLING TESTS				
Sample	**Analysis**	**Frequency**	**Maximum Time Between Analysis**	L.3
~~1. Reactor Coolant~~ SR 3.4.16.1	~~Gross Activity~~(1)	~~5 days/week~~(1)(4)	~~3 days~~(1)	
	Tritium Activity	Weekly(1)	10 days	LA.2
	Boron concentration	2 days/week	5 days	LA.3
	~~Radiochemical (gamma)~~(2) ~~Spectral Check~~	~~Monthly~~	~~45 days~~	L.3
	Oxygen and Chlorides Concentration	3 times per 7 days	3 days	
	Fluorides Concentration	Weekly	10 days	
SR 3.4.16.3	Ē Determination (3)	Semi-Annually 184 days	30 weeks SR 3.0.2	L.1
SR 3.4.16.2	Isotopic Analysis for I-131, I-133, I-135	Once per 14 days(3)	20 days SR 3.0.2	M.1
2. Boric Acid Tank	Boron Concentration, Chlorides	Weekly	10 days	
3. Spray Additive Tank	NaOH Concentration	Monthly	45 days	
4. Accumulators	Boron Concentration	Monthly	45 days	
5. Refueling Water Storage Tank	Boron Concentration pH, Chlorides	Monthly	45 days	
	Gross Activity	Quarterly	16 weeks	
6. Secondary Coolant	I-131 Equivalent (Isotopic Analysis)	Monthly	45 days	
	Gross Activity	3 times per 7 days	3 days	
7. Component Cooling Water	Gross Activity, Corrosion Inhibitor and pH	Monthly	45 days	
8. Spent Fuel Pool (when fuel stored)	Gross Activity Boron Concentration, Chlorides	Monthly	45 days	

TABLE 4.1-2 (Sheet 1 of 2)

FREQUENCIES FOR SAMPLING TESTS

Sample	Analysis	Frequency	Maximum Time Between Analysis
1. Reactor Coolant	Gross Activity(1)	5 days/week(1)(4)	3 days(4)
	Tritium Activity	Weekly(1)	10 days
	Boron concentration	2 days/week	5 days
	Radiochemical (gamma)(2) Spectral Check	Monthly	45 days
	Oxygen and Chlorides Concentration %	3 times per 7 days	3 days
	Fluorides Concentration	Weekly	10 days
	Ē Determination (2)	Semi-Annually	30 weeks
	Isotopic Analysis for I-131, I-133, I-135	Once per 14 days(3)	20 days
2. Boric Acid Tank	Boron Concentration, Chlorides	Weekly	10 days
3. Spray Additive Tank	NaOH Concentration	Monthly	45 days
4. Accumulators	Boron Concentration	Monthly — 31days	45 days
5. Refueling Water Storage Tank	Boron Concentration pH, Chlorides	Monthly	45 days
	Gross Activity	Quarterly	16 weeks
6. Secondary Coolant	I-131 Equivalent (Isotopic Analysis)	Monthly	45 days
	Gross Activity	3 times per 7 days	3 days
7. Component Cooling Water	Gross Activity, Corrosion Inhibitor and pH	Monthly	45 days
8. Spent Fuel Pool (when fuel stored)	Gross Activity Boron Concentration, Chlorides	Monthly	45 days

SR3.5.1.4

M.2

Amendment No. 139

Add SR3.5.1.4 accelerated Frequency

M.5

ITS 3.5.1

TABLE 4.1-2 (Sheet 1 of 2)

FREQUENCIES FOR SAMPLING TESTS

SR 3.5.4.3

SEE Relocated

Sample	**Analysis**	**Frequency**	**Maximum Time Between Analysis**
1. Reactor Coolant	Gross Activity[1]	5 days/week[1][4]	3 days[4]
	Tritium Activity	Weekly[1]	10 days
	Boron concentration	2 days/week	5 days
	Radiochemical (gamma)[2] Spectral Check	Monthly	45 days
	Oxygen and Chlorides Concentration	3 times per 7 days	3 days
	Fluorides Concentration	Weekly	10 days
	$\bar{E}$ Determination [3]	Semi-Annually	30 weeks
	Isotopic Analysis for I-131, I-133, I-135	Once per 14 days[5]	20 days
2. Boric Acid Tank	Boron Concentration, Chlorides	Weekly	10 days
3. Spray Additive Tank	NaOH Concentration	Monthly	45 days
4. Accumulators	Boron Concentration	Monthly	45 days
5. Refueling Water Storage Tank	Boron Concentration	Monthly 31 days	45 days M.3
	pH, Chlorides		
	Gross Activity	Quarterly	16 weeks
6. Secondary Coolant	I-131 Equivalent (Isotopic Analysis)	Monthly	45 days
	Gross Activity	3 times per 7 days	3 days
7. Component Cooling Water	Gross Activity, Corrosion Inhibitor and pH	Monthly	45 days
8. Spent Fuel Pool (when fuel stored)	Gross Activity Boron Concentration, Chlorides	Monthly	45 days

Amendment No. 139

ITS 3.5.4

TABLE 4.1-2 (Sheet 1 of 2)

SEE CTS MASTER MARKUP

FREQUENCIES FOR SAMPLING TESTS			
Sample	**Analysis**	**Frequency**	**Maximum Time Between Analysis**
1. Reactor Coolant	Gross Activity[1]	5 days/week[1][4]	3 days[4]
	Tritium Activity	Weekly[1]	10 days
	Boron concentration	2 days/week	5 days
	Radiochemical (gamma)[2] Spectral Check	Monthly	45 days
	Oxygen and Chlorides Concentration	3 times per 7 days	3 days
	Fluorides Concentration	Weekly	10 days
	$\bar{E}$ Determination [3]	Semi-Annually	30 weeks
	Isotopic Analysis for I-131, I-133, I-135	Once per 14 days[5]	20 days
2. Boric Acid Tank	Boron Concentration, Chlorides	Weekly	10 days
SR 3.6.7.3 3. Spray Additive Tank	NaOH Concentration	~~Monthly~~	~~45 days~~ 184 days L.3
4. Accumulators	Boron Concentration	Monthly	45 days
5. Refueling Water Storage Tank	Boron Concentration pH, Chlorides	Monthly	45 days
	Gross Activity	Quarterly	16 weeks
6. Secondary Coolant	I-131 Equivalent (Isotopic Analysis)	Monthly	45 days
	Gross Activity	3 times per 7 days	3 days
7. Component Cooling Water	Gross Activity, Corrosion Inhibitor and pH	Monthly	45 days
8. Spent Fuel Pool (when fuel stored)	Gross Activity Boron Concentration, Chlorides	Monthly	45 days

SEE CTS MASTER MARKUR

ITS 3.6.7

TABLE 4.1-2 (Sheet 1 of 2)

FREQUENCIES FOR SAMPLING TESTS			
Sample	**Analysis**	**Frequency**	**Maximum Time Between Analysis**
1. Reactor Coolant	Gross Activity(1)	5 days/week(1)(4)	3 days(4)
	Tritium Activity	Weekly(1)	10 days
	Boron concentration	2 days/week	5 days
	Radiochemical (gamma)(2) Spectral Check	Monthly	45 days
	Oxygen and Chlorides Concentration	3 times per 7 days	3 days
	Fluorides Concentration	Weekly	10 days
	$\bar{E}$ Determination (2)	Semi-Annually	30 weeks
	Isotopic Analysis for I-131, I-133, I-135	Once per 14 days(3)	20 days
2. Boric Acid Tank	Boron Concentration, Chlorides	Weekly	10 days
3. Spray Additive Tank	NaOH Concentration	Monthly	45 days
4. Accumulators	Boron Concentration	Monthly	45 days
5. Refueling Water Storage Tank	Boron Concentration pH, Chlorides	Monthly	45 days
	Gross Activity	Quarterly	16 weeks
6. Secondary Coolant	I-131 Equivalent (Isotopic Analysis)	Monthly	45 days
	Gross Activity	3 times per 7 days	3 days
LCO 3.7.8 ~~7. Component Cooling Water~~	~~Gross Activity, Corrosion Inhibitor and pH~~	~~Monthly~~	~~45 days~~ LA.2
8. Spent Fuel Pool (when fuel stored)	Gross Activity Boron Concentration, Chlorides	Monthly	45 days

Amendment No. 139

ITS 3.7.8

TABLE 4.1-2 (Sheet 1 of 2)

SEE CTS MASTER MARKUP

FREQUENCIES FOR SAMPLING TESTS			
Sample	**Analysis**	**Frequency**	**Maximum Time Between Analysis**
1. Reactor Coolant	Gross Activity(1) Tritium Activity Boron concentration Radiochemical (gamma)(2) Spectral Check Oxygen and Chlorides Concentration Fluorides Concentration Ē Determination (3) Isotopic Analysis for I-131, I-133, I-135	5 days/week(1)(4) Weekly(1) 2 days/week Monthly 3 times per 7 days Weekly Semi-Annually Once per 14 days(3)	3 days(4) 10 days 5 days 45 days 3 days 10 days 30 weeks 20 days
2. Boric Acid Tank	Boron Concentration, Chlorides	Weekly	10 days
3. Spray Additive Tank	NaOH Concentration	Monthly	45 days
4. Accumulators	Boron Concentration	Monthly	45 days
5. Refueling Water Storage Tank	Boron Concentration pH, Chlorides Gross Activity	Monthly Quarterly	45 days 16 weeks
6. Secondary Coolant	I-131 Equivalent (Isotopic Analysis) Gross Activity	Monthly 3 times per 7 days	45 days 3 days
7. Component Cooling Water	Gross Activity, Corrosion Inhibitor and pH	Monthly	45 days
SR 3.7.15.1 — 8. Spent Fuel Pool (when fuel stored)	Gross Activity Boron Concentration, Chlorides	Monthly	45 days

SEE RELOCATED CTS

7 days unless pool verification completed

L.1

A.3

Amendment No. 139

ITS 3.7.1

TABLE 4.1-2 (Sheet 1 of 2)

FREQUENCIES FOR SAMPLING TESTS

Sample	Analysis	Frequency	Maximum Time Between Analysis
1. Reactor Coolant	Gross Activity(1)	5 days/week(1)(4)	3 days(4)
	Tritium Activity	Weekly(1)	10 days
	Boron concentration	2 days/week	5 days
	Radiochemical (gamma)(2) Spectral Check	Monthly	45 days
	Oxygen and Chlorides Concentration	3 times per 7 days	3 days
	Fluorides Concentration	Weekly	10 days
	$\bar{E}$ Determination (2)	Semi-Annually	30 weeks
	Isotopic Analysis for I-131, I-133, I-135	Once per 14 days(3)	20 days
2. Boric Acid Tank	Boron Concentration, Chlorides	Weekly	10 days
3. Spray Additive Tank	NaOH Concentration	Monthly	45 days
4. Accumulators	Boron Concentration	Monthly	45 days
5. Refueling Water Storage Tank	Boron Concentration pH, Chlorides	Monthly	45 days
	Gross Activity	Quarterly	16 weeks
SR 3.7.17.1 6. Secondary Coolant	I-131 Equivalent (Isotopic Analysis)	Monthly 31 days	45 days SR 3.0.2 M.2
	Gross Activity	3 times per 7 days	3 days
7. Component Cooling Water	Gross Activity, Corrosion Inhibitor and pH	Monthly	45 days
8. Spent Fuel Pool (when fuel stored)	Gross Activity Boron Concentration, Chlorides	Monthly	45 days

ITS 3.7.17

TABLE 4.1-2 (Sheet 1 of 2)

FREQUENCIES FOR SAMPLING TESTS			
Sample	Analysis	Frequency	Maximum Time Between Analysis
1. Reactor Coolant	Gross Activity[1]	5 days/week[1][4]	3 days[4]
	Tritium Activity	Weekly[1]	10 days
	Boron concentration	2 days/week	5 days
	Radiochemical (gamma)[2] Spectral Check	Monthly	45 days
	Oxygen and Chlorides Concentration	3 times per 7 days	3 days
	Fluorides Concentration	Weekly	10 days
	$\bar{E}$ Determination [2]	Semi-Annually	30 weeks
	Isotopic Analysis for I-131, I-133, I-135	Once per 14 days[3]	20 days
2. Boric Acid Tank	Boron Concentration, Chlorides	Weekly	10 days
3. Spray Additive Tank	NaOH Concentration	Monthly	45 days
4. Accumulators	Boron Concentration	Monthly	45 days
5. Refueling Water Storage Tank	Boron Concentration pH, Chlorides	Monthly	45 days
	Gross Activity	Quarterly	16 weeks
6. Secondary Coolant	I-131 Equivalent (Isotopic Analysis)	Monthly	45 days
	Gross Activity	3 times per 7 days	3 days
7. Component Cooling Water	Gross Activity, Corrosion Inhibitor and pH	Monthly	45 days
8. Spent Fuel Pool (when fuel stored)	Gross Activity Boron Concentration, Chlorides	Monthly	45 days

SEE CTS MASTER MARKUP

R.4

R.4

R.4

Relocated Item (R-4)

SEE CTS MASTER MARKUP

TABLE 4.1-2 (Sheet 1 of 2)

FREQUENCIES FOR SAMPLING TESTS

Sample	Analysis	Frequency	Maximum Time Between Analysis
1. Reactor Coolant	Gross Activity[1]	5 days/week[1][4]	3 days[4]
	Tritium Activity	Weekly[1]	10 days
	Boron concentration	2 days/week	5 days
	Radiochemical (gamma)[2] Spectral Check	Monthly	45 days
	Oxygen and Chlorides Concentration	3 times per 7 days	3 days
	Fluorides Concentration	Weekly	10 days
	$\bar{E}$ Determination [3]	Semi-Annually	30 weeks
	Isotopic Analysis for I-131, I-133, I-135	Once per 14 days[3]	20 days
2. ~~Boric Acid Tank~~	~~Boron Concentration, Chlorides~~	~~Weekly~~	~~10 days~~
3. Spray Additive Tank	NaOH Concentration	Monthly	45 days
4. Accumulators	Boron Concentration	Monthly	45 days
5. Refueling Water Storage Tank	Boron Concentration pH, Chlorides	Monthly	45 days
	Gross Activity	Quarterly	16 weeks
6. Secondary Coolant	I-131 Equivalent (Isotopic Analysis)	Monthly	45 days
	Gross Activity	3 times per 7 days	3 days
7. Component Cooling Water	Gross Activity, Corrosion Inhibitor and pH	Monthly	45 days
8. Spent Fuel Pool (when fuel stored)	Gross Activity Boron Concentration, Chlorides	Monthly	45 days

R5

Relocated Item (R-5)

TABLE 4.1-2 *(Sheet 2 of 2)*

FREQUENCIES FOR SAMPLING TESTS

FOOTNOTES:

SR 3.4.16.1

(1) ~~A gross activity analysis shall consist of the quantitative measurement of the total radioactivity of the primary coolant in units of μCi/cc.~~

(2) ~~A radiochemical analysis shall consist of the quantitative measurement of each radionuclide with half life greater than 10 minutes making up at least 95% of the total activity of the primary coolant.~~

LA.1 M2 L3

SR 3.4.16.3

~~(3)~~ $\bar{E}$ determination will be ~~started when the gross activity analysis indicates ≥ 10 μCi/cc~~ and ~~will be redetermined if the primary coolant gross radioactivity changes by more than 10 μCi/cc in accordance with Specification 3.1.D~~

L.2 L.4

SEE RELOCATED

(4) Whenever the Gross Failed Fuel Monitor is inoperable, the sampling frequency shall be increased to twice per day, five days per week. The maximum time between analyses shall be sixteen hours for the two samples taken on a given day and three days between daily analysis. This accelerated sampling frequency need only be performed until the Gross Failed Fuel Monitor is declared operable.

Req. Act A.1

SR 3.4.16.2 Frequency

(5) Once per 4 hours whenever the DOSE EQUIVALENT I-131 exceeds 1.0 μCi/cc or one sample after two hours but before six hours following a thermal power change exceeding 15 percent of the rated thermal power within a one-hour period.

Note to SR 3.4.16.3

TABLE 4.1-3 (Sheet 1 of 2)

FREQUENCIES FOR EQUIPMENT TESTS

		Check	Frequency
SR3.1.4.3	~~1.~~ Control Rods	Rod drop times of all control rods	Prior to critical after head removed 24M M
SR 3.1.4.2	2. Control Rods	Movement of at least 10 steps in any one direction of all control rods except fully inserted rods A.	Every 31 92 days ~~during reactor critical operations~~ A.4 L.2
	3. Pressurizer Safety Valves	Set Point	24M*
	4. Main Steam Safety Valves	Set Point	24M
	5. Containment Isolation System	Automatic actuation	24M
	6. Refueling System Interlocks	Functioning	Each refueling, prior to movement of core components
	7. Primary System Leakage	Evaluate	5 days/week
	8. Diesel Generators Nos. 31, 32 & 33 Fuel Supply	Fuel Inventory	Weekly
	9. Turbine Steam Stop Control Valves	Closure	Yearly
	10. L.P. Steam Dump System (6 lines)	Closure	Monthly
	11. Service Water System	Each pump starts and operates for 15 minutes (unless already operating)	Quarterly
	12. City Water Connections to Charging Pumps and Boric Acid Piping	Temporary connections available and valves operable	24M

* ~~Pressurizer Safety Valve setpoint test due no later than May 1996 may be deferred until the next refueling outage but no later than May 31, 1997.~~ Deleted L TSCR 97-1

Insert from TSCR 98-043.

TSCR 97-156

TSCR 98-043

TABLE 4.1-3 (Sheet 1 of 2)

FREQUENCIES FOR EQUIPMENT TESTS

SEE CTS MASTER MARKUP

	Check	Frequency
1. Control Rods	Rod drop times of all control rods	24M
2. Control Rods	Movement of at least 10 steps in any one direction of all control rods	Every 31 days during reactor critical operations
3. Pressurizer Safety Valves	Set Point	24M* IAW Inservice Test Program
4. ~~Main Steam~~ Safety Valves	~~Set Point~~	24M
5. Containment Isolation System	Automatic actuation	24M
6. Refueling System Interlocks	Functioning	Each refueling, prior to movement of core components
7. Primary System Leakage	Evaluate	5 days/week
8. Diesel Generators Nos. 31, 32 & 33 Fuel Supply	Fuel Inventory	Weekly
9. Turbine Steam Stop And Control Valves	Closure	Not to exceed 6 months**
10. L.P. Steam Dump System (6 lines)	Closure	Monthly
11. Service Water System	Each pump starts and operates for 15 minutes (unless already operating)	Monthly
12. City Water Connections to Charging Pumps and Boric Acid Piping	Temporary connections available and valves operable	24M

SR 3.4.10.1 LA.2

SEE CTS MASTER MARKUP

* ~~Pressurizer Safety Valve setpoint test due no later than May 1996 may be deferred until the next refueling outage but no later than May 31, 1997.~~ TSCR 97-156 A.4

SEE CTS RELOCATED

** The turbine steam stop and control valves shall be tested at a frequency determined by the methodology presented in WCAP-11525, "Probabilistic Evaluation of Reduction in Turbine Valve Test Frequency," as updated by Westinghouse Report, WOG-TVTF-93-17, "Update of BB-95/96 Turbine Valve Failure Rates and Effect on Destructive Overspeed Probabilities." The maximum test interval for these valves shall not exceed six months. Surveillance interval extension as per Technical Specification 1.12 is not applicable to the maximum test interval.

Add SR 3.4.13.2

A.5

TABLE 4.1-3 (Sheet 1 of 2)

FREQUENCIES FOR EQUIPMENT TESTS

		Check	Frequency
SEE CTS MASTER MARKUP	1. Control Rods	Rod drop times of all control rods	24M
	2. Control Rods	Movement of at least 10 steps in any one direction of all control rods	Every 31 days during reactor critical operations
	3. Pressurizer Safety Valves	Set Point	24M*
	4. Main Steam Safety Valves	Set Point	24M
	5. Containment Isolation System	Automatic actuation	24M
	6. Refueling System Interlocks	Functioning	Each refueling, prior to movement of core components
SR 3.4.13.1	7. Primary System Leakage	Evaluate Add SR 3.4.13.1 Note	~~5 days/week~~ 72 hours
SEE CTS MASTER MARKUP	8. Diesel Generators Nos. 31, 32 & 33 Fuel Supply	Fuel Inventory	Weekly
	9. Turbine Steam Stop And Control Valves	Closure	Not to exceed 6 months**
	10. L.P. Steam Dump System (6 lines)	Closure	Monthly
	11. Service Water System	Each pump starts and operates for 15 minutes (unless already operating)	Monthly
	12. City Water Connections to Charging Pumps and Boric Acid Piping	Temporary connections available and valves operable	24M

A.5 L.7 L.6

* ~~Pressurizer Safety Valve setpoint test due no later than May 1996 may be deferred until the next refueling outage but no later than May 31, 1997.~~ TSCR 97-156

** The turbine steam stop and control valves shall be tested at a frequency determined by the methodology presented in WCAP-11525, "Probabilistic Evaluation of Reduction in Turbine Valve Test Frequency," as updated by Westinghouse Report, WOG-TVTF-93-17, "Update of BB-95/96 Turbine Valve Failure Rates and Effect on Destructive Overspeed Probabilities." The maximum test interval for these valves shall not exceed six months. Surveillance interval extension as per Technical Specification 1.12 is not applicable to the maximum test interval.

TSCR 98-043

TSCR 97-156

Add SR 3.6.3.5

M.4

TABLE 4.1-3 (Sheet 1 of 2)

FREQUENCIES FOR EQUIPMENT TESTS

SEE CTS MASTER MARKUP

		Check	Frequency
1.	Control Rods	Rod drop times of all control rods	24M
2.	Control Rods	Movement of at least 10 steps in any one direction of all control rods	Every 31 days during reactor critical operations
3.	Pressurizer Safety Valves	Set Point	24M*
4.	Main Steam Safety Valves	Set Point	24M
5.	Containment Isolation System	Automatic actuation	24M
6.	Refueling System Interlocks	Functioning	Each refueling, prior to movement of core components
7.	Primary System Leakage	Evaluate	5 days/week
8.	Diesel Generators Nos. 31, 32 & 33 Fuel Supply	Fuel Inventory	Weekly
9.	Turbine Steam Stop And Control Valves	Closure	Not to exceed 6 months**
10.	L.P. Steam Dump System (6 lines)	Closure	Monthly
11.	Service Water System	Each pump starts and operates for 15 minutes (unless already operating)	Monthly
12.	City Water Connections to Charging Pumps and Boric Acid Piping	Temporary connections available and valves operable	24M

SR 3.6.3.6 (item 5)

SEE CTS MASTER MARKUP

* ~~Pressurizer Safety Valve setpoint test due no later than May 1996 may be deferred until the next refueling outage but no later than May 31, 1997.~~ TSCR 97-156

** The turbine steam stop and control valves shall be tested at a frequency determined by the methodology presented in WCAP-11525, "Probabilistic Evaluation of Reduction in Turbine Valve Test Frequency," as updated by Westinghouse Report, WOG-TVTF-93-17, "Update of BB-95/96 Turbine Valve Failure Rates and Effect on Destructive Overspeed Probabilities." The maximum test interval for these valves shall not exceed six months. The Surveillance interval extension as per Technical Specification 1.12 is not applicable to the maximum test interval.

TSCR 98-043

TSCR 97-156

TABLE 4.1-3 (Sheet 1 of 2)

FREQUENCIES FOR EQUIPMENT TESTS

SEE CTS MASTER MARKUP

SR 3.7.1.1

	Check	Frequency
1. Control Rods	Rod drop times of all control rods	24M
2. Control Rods	Movement of at least 10 steps in any one direction of all control rods	Every 31 days during reactor critical operations
3. Pressurizer Safety Valves	Set Point	24M*
4. Main Steam Safety Valves	~~Set Point~~ Setpoint, Tolerance adjust	24M Per IST Program L.2 LA.1
5. Containment Isolation System	Automatic actuation	24M
6. Refueling System Interlocks	Functioning	Each refueling, prior to movement of core components
7. Primary System Leakage	Evaluate	5 days/week
8. Diesel Generators Nos. 31, 32 & 33 Fuel Supply	Fuel Inventory	Weekly
9. Turbine Steam Stop And Control Valves	Closure	Not to exceed 6 months**
10. L.P. Steam Dump System (6 lines)	Closure	Monthly
11. Service Water System	Each pump starts and operates for 15 minutes (unless already operating)	~~Monthly~~ Quarterly Amendment 178
12. City Water Connections to Charging Pumps and Boric Acid Piping	Temporary connections available and valves operable	24M

M.1

SEE CTS MASTER MARKUP

* ~~Pressurizer Safety Valve setpoint test due no later than May 1996 may be deferred until the next refueling outage but no later than May 31, 1997.~~ TSCR 97-156

** The turbine steam stop and control valves shall be tested at a frequency determined by the methodology presented in WCAP-11525, "Probabilistic Evaluation of Reduction in Turbine Valve Test Frequency," as updated by Westinghouse Report, WOG-TVTF-93-17, "Update of BB-95/96 Turbine Valve Failure Rates and Effect on Destructive Overspeed Probabilities." The maximum test interval for these valves shall not exceed six months. The Surveillance interval extension as per Technical Specification 1.12 is not applicable to the maximum test interval.

TSCR 98-043

TSCR 97-156

SEE CTS MASTER MARKUP

TABLE 4.1-3 (Sheet 1 of 2)

FREQUENCIES FOR EQUIPMENT TESTS

	Check	Frequency
1. Control Rods	Rod drop times of all control rods	24M
2. Control Rods	Movement of at least 10 steps in any one direction of all control rods	Every 31 days during reactor critical operations
3. Pressurizer Safety Valves	Set Point	24M*
4. Main Steam Safety Valves	Set Point	24M
5. Containment Isolation System	Automatic actuation	24M
6. Refueling System Interlocks	Functioning	Each refueling, prior to movement of core components
7. Primary System Leakage	Evaluate	5 days/week
8. Diesel Generators Nos. 31, 32 & 33 Fuel Supply	Fuel Inventory	Weekly
9. Turbine Steam Stop And Control Valves	Closure	Not to exceed 6 months**
10. L.P. Steam Dump System (6 lines)	Closure	Monthly
LCO 3.7.9 11. Service Water System	Each pump starts and operates for 15 minutes (unless already operating)	~~Monthly~~ TSCR Quarterly LA.2
12. City Water Connections to Charging Pumps and Boric Acid Piping	Temporary connections available and valves operable	24M

SEE CTS MASTER MARKUP

* ~~Pressurizer Safety Valve setpoint test due no later than May 1996 may be deferred until the next refueling outage but no later than May 31, 1997.~~ TSCR 97-156

** The turbine steam stop and control valves shall be tested at a frequency determined by the methodology presented in WCAP-11525, "Probabilistic Evaluation of Reduction in Turbine Valve Test Frequency," as updated by Westinghouse Report, WOG-TVTF-93-17, "Update of BB-95/96 Turbine Valve Failure Rates and Effect on Destructive Overspeed Probabilities." The maximum test interval for these valves shall not exceed six months. Surveillance interval extension as per Technical Specification 1.12 is not applicable to the maximum test interval.

TABLE 4.1-3 (Sheet 1 of 2)

FREQUENCIES FOR EQUIPMENT TESTS

SEE MASTER MARKUP

	Check	Frequency
1. Control Rods	Rod drop times of all control rods	24M
2. Control Rods	Movement of at least 10 steps in any one direction of all control rods	Every 31 days during reactor critical operations
3. Pressurizer Safety Valves	Set Point	24M*
4. Main Steam Safety Valves	Set Point	24M
5. Containment Isolation System	Automatic actuation	24M
6. Refueling System Interlocks	Functioning	Each refueling, prior to movement of core components
7. Primary System Leakage	Evaluate	5 days/week
8. Diesel Generators Nos. 31, 32 & 33 Fuel Supply	Fuel Inventory in day tank ≥ 115 gal	~~Weekly~~ 31 days
9. Turbine Steam Stop And Control Valves	Closure	Not to exceed 6 months**
10. L.P. Steam Dump System (6 lines)	Closure	Monthly
11. Service Water System	Each pump starts and operates for 15 minutes (unless already operating)	Monthly
12. City Water Connections to Charging Pumps and Boric Acid Piping	Temporary connections available and valves operable	24M

SR 3.8.1.4 (SEE ALSO ITS 3.8.3)

A.

L.

SEE MASTER MARKUP

* ~~Pressurizer Safety Valve setpoint test due no later than May 1996 may be deferred until the next refueling outage but no later than May 31, 1997~~ TSCR 98-043

** The turbine steam stop and control valves shall be tested at a frequency determined by the methodology presented in WCAP-11525, "Probabilistic Evaluation of Reduction in Turbine Valve Test Frequency," as updated by Westinghouse Report, WOG-TVTF-93-17, "Update of BB-95/96 Turbine Valve Failure Rates and Effect on Destructive Overspeed Probabilities." The maximum test interval for these valves shall not exceed six months. Surveillance interval extension as per Technical Specification 1.12 is not applicable to the maximum test interval.

TSCR 97-156 and TSCR 98-043

TABLE 4.1-3 (Sheet 1 of 2)

FREQUENCIES FOR EQUIPMENT TESTS

SEE CTS MASTER MARKUP

	Check	Frequency
1. Control Rods	Rod drop times of all control rods	24M
2. Control Rods	Movement of at least 10 steps in any one direction of all control rods	Every 31 days during reactor critical operations
3. Pressurizer Safety Valves	Set Point	24M*
4. Main Steam Safety Valves	Set Point	24M
5. Containment Isolation System	Automatic actuation	24M
6. Refueling System Interlocks	Functioning	Each refueling, prior to movement of core components
7. Primary System Leakage	Evaluate	5 days/week
8. Diesel Generators Nos. 31, 32 & 33 Fuel Supply	Fuel Inventory	Weekly SR 3.8.3.1 24 hr M. SR 3.8.3.2 31 days L.1
9. Turbine Steam Stop And Control Valves	Closure	Not to exceed 6 months**
10. L.P. Steam Dump System (6 lines)	Closure	Monthly
11. Service Water System	Each pump starts and operates for 15 minutes (unless already operating)	Monthly
12. City Water Connections to Charging Pumps and Boric Acid Piping	Temporary connections available and valves operable	24M

SR 3.8.3.1
SR 3.8.3.2

SEE CTS MASTER MARKUP

* ~~Pressurizer Safety Valve setpoint test due no later than May 1996 may be deferred until the next refueling outage but no later than May 31, 1997~~ TSCR 98-043

** The turbine steam stop and control valves shall be tested at a frequency determined by the methodology presented in WCAP-11525, "Probabilistic Evaluation of Reduction in Turbine Valve Test Frequency," as updated by Westinghouse Report, WOG-TVTF-93-17, "Update of BB-95/96 Turbine Valve Failure Rates and Effect on Destructive Overspeed Probabilities." The maximum test interval for these valves shall not exceed six months. Surveillance interval extension as per Technical Specification 1.12 is not applicable to the maximum test interval.

Amendment No. ~~10~~, ~~14~~, ~~41~~, ~~65~~, ~~91~~, ~~99~~, ~~125~~, ~~126~~, ~~127~~, ~~129~~, ~~131~~, ~~144~~, ~~168~~,
TSCR 97-156 and TSCR 98-043

Relocated Item (R-5)

TABLE 4.1-3 (Sheet 1 of 2)

FREQUENCIES FOR EQUIPMENT TESTS

SEE CTS MASTER MARKUP

	Check	Frequency
1. Control Rods	Rod drop times of all control rods	24M
2. Control Rods	Movement of at least 10 steps in any one direction of all control rods	Every 31 days during reactor critical operations
3. Pressurizer Safety Valves	Set Point	24M*
4. Main Steam Safety Valves	Set Point	24M
5. Containment Isolation System	Automatic actuation	24M
6. Refueling System Interlocks	Functioning	Each refueling, prior to movement of core components
7. Primary System Leakage	Evaluate	5 days/week
8. Diesel Generators Nos. 31, 32 & 33 Fuel Supply	Fuel Inventory	Weekly
9. Turbine Steam Stop Control Valves	Closure	Yearly
10. L.P. Steam Dump System (6 lines)	Closure	Monthly
11. Service Water System	Each pump starts and operates for 15 minutes (unless already operating)	Quarterly
12. City Water Connections to Charging Pumps and Boric Acid Piping	Temporary connections available and valves operable	24M

R.5

R.5

* Pressurizer Safety Valve setpoint test due no later than May 1996 may be deferred until the next refueling outage but no later than May 31, 1997.

Relocated Item (R-7)

TABLE 4.1-3 (Sheet 1 of 2)

FREQUENCIES FOR EQUIPMENT TESTS		
	Check	Frequency
1. Control Rods	Rod drop times of all control rods	24M
2. Control Rods	Movement of at least 10 steps in any one direction of all control rods	Every 31 days during reactor critical operations
3. Pressurizer Safety Valves	Set Point	24M*
4. Main Steam Safety Valves	Set Point	24M
5. Containment Isolation System	Automatic actuation	24M
6. Refueling System Interlocks	Functioning	Each refueling, prior to movement of core components
7. Primary System Leakage	Evaluate	5 days/week
8. Diesel Generators Nos. 31, 32 & 33 Fuel Supply	Fuel Inventory	Weekly
~~9. Turbine Steam Stop Control Valves~~	~~Closure~~	~~Yearly~~
~~10. L.P. Steam Dump System (6 lines)~~	~~Closure~~	~~Monthly~~
11. Service Water System	Each pump starts and operates for 15 minutes (unless already operating)	Quarterly
12. City Water Connections to Charging Pumps and Boric Acid Piping	Temporary connections available and valves operable	24M

SEE CTS MASTER MARKUP

R.7

R.7

SEE CTS MASTER MARKUP

* Pressurizer Safety Valve setpoint test due no later than May 1996 may be deferred until the next refueling outage but no later than May 31, 1997.

TABLE 4.1-3 (Sheet 2 of 2)

SEE ITS 3.4.14	13. RHR Valves 730 and 731	Automatic isolation and interlock action	24M
SR 3.4.11.1	14. PORV Block Valves	Operability through 1 complete cycle of full travel	Quarterly (see Note 1) 92 days
SR 3.4.11.2	15. PORV Valves	Operability	24M
SEE RELOCATED	16. Reactor Vessel Head Vents	Operability	24M

24M - At least once per 24 months

Note 1. ~~If the block valve is shut due to a leaking or inoperable PORV, Block Valve operability will be checked the next time the plant is in cold shutdown.~~ A.6

at ≥ 550 psig

at ≥ 450 psig

M.3

TABLE 4.1-3 (Sheet 2 of 2)

SR 3.4.14.2 SR 3.4.14.3	13. RHR Valves 730 and 731	Automatic isolation and interlock action	24M
SEE ITS 3.4.11	14. PORV Block Valves	Operability through 1 complete cycle of full travel	~~Quarterly (see Note 1)~~
	15. PORV Valves	Operability	24M
SEE RELOCATED	16. Reactor Vessel Head Vents	Operability	24M

~~24M - At least once per 24 months~~

SEE ITS 3.4.11 — Note 1. If the block valve is shut due to a leaking or inoperable PORV, Block Valve operability will be checked the next time the plant is in cold shutdown.

Add Condition C and associated Req. Action — M.2

Relocated Item (R-1)

TABLE 4.1-3 (Sheet 2 of 2)

SEE ITS 3.4.11 ITS 3.4.14

13. RHR Valves 730 and 731	Automatic isolation and interlock action	24M
14. PORV Block Valves	Operability through 1 complete cycle of full travel	Quarterly (see Note 1)
15. PORV Valves	Operability	24M
~~16. Reactor Vessel Head Vents~~	~~Operability~~	~~24M~~

R.1

24M - At least once per 24 months

SEE ITS 3.4.11

Note 1. If the block valve is shut due to a leaking or inoperable PORV, Block Valve operability will be checked the next time the plant is in cold shutdown.

A.1

5.5.7 ~~4.2~~ INSERVICE INSPECTION Inservice Testing Program A.3

~~4.2.1~~ WELD AND SUPPORT PROGRAM

A.2

~~4.2.1.1~~ ~~APPLICABILITY~~

~~Applies to in-service surveillance of ASME Code Class 1,2, and 3 systems welds and supports.~~

~~4.2.1.2~~ ~~OBJECTIVE~~

~~To assure the continued integrity and functionability of welds and supports in ASME Code Class 1,2, and 3 systems.~~ A.3

~~4.2.1.3~~ SPECIFICATION

a. ~~Inservice inspection of ASME Code Class 1,2, and 3 components shall be performed in accordance with Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda as required by 10 CFR 50, Section 50.55a(g), except where specific written relief has been granted by the Commission pursuant to 10 CFR 50, Section 50.55a (g) (6) (i).~~ A.

~~b.~~ ~~Performance of the above inservice inspection and testing activities shall be in addition to other specified Surveillance Requirements.~~ A.3

5.5.7.d ~~c.~~ Nothing in the ASME Boiler and Pressure Vessel Code shall be construed to supersede the requirements of any Technical Specification.

LA.

d. ~~Detailed records of each inspection shall be maintained to allow comparison and evaluation of future inspections.~~

Add ITS 5.5.7.a, Testing Frequencies A.6

Add ITS 5.5.7.b, SR 3.0.2 Applicable A.4

Add ITS 5.5.7.c, SR 3.0.3 Applicability A.5

4.2.1.4 ~~BASES~~

~~This specification ensures that inservice inspection of ASME Code Class 1,2 and 3 components will be performed in accordance with a periodically updated version of Section XI of the ASME Boiler and Pressure Vessel Code and Addenda as required by 10 CFR 50.55a. Relief from any of the above requirements has been provided in writing by the Commission and is not a part of these Technical Specifications.~~

~~Under the terms of this Specification, the more restrictive requirements of the Technical Specifications take precedence over the ASME Boiler and Pressure Vessel Code and applicable Addenda.~~

A.

A.1

DELETED

Figure 4.2-1 Steam Generator Primary Side Ultrasonic Test Sensors

4.3 REACTOR COOLANT SYSTEM (RCS) TESTING

A. Reactor Coolant System Integrity Testing

A.2

~~Applicability~~

~~Applies to test requirements for Reactor Coolant System integrity.~~

~~Objective~~

~~To specify tests for Reactor Coolant System integrity after the system is closed following refueling, repair, replacement or modification.~~

Specification

SEE RELOCATED CTS

a) The Reactor Coolant System shall be tested for leakage at normal operating pressure prior to plant startup following each refueling outage, in accordance with the requirements of ASME Section XI.

b) Testing of repairs, replacements or modifications for the Reactor Coolant System shall meet the requirements of ASME Section XI.

LCO 3.4.3

~~c)~~ The Reactor Coolant System leak test temperature-pressure relationship shall be in accordance with the limits of ~~Figure 4.3-1 for heatup for the first 13.3 EFPYs of operations. Figure 4.3-1 will be recalculated periodically.~~ PTLR Allowable pressures during cooldown from the leak test temperature shall be in accordance with ~~Figure 3.1-2~~.

LA.1

~~Basis~~

~~Leak test of the Reactor Coolant System is required by the ASME Boiler and Pressure Vessel Code, Section XI, to ensure leak tightness of the system during operation. The test frequency and conditions are specified in the Code.~~

~~For repairs on components, the thorough non-destructive testing gives a very high degree of confidence in the integrity of the system, and will detect any significant defects in and near the new welds. In all cases, the leak test will assure leak tightness during normal operation.~~

~~The inservice leak test temperatures are shown on Figure 4.3-1. The temperatures are calculated in accordance with ASME Code Section III, Appendix G. This Code requires that a safety factor of 1.5 times the stress intensity factor caused by pressure be applied to the calculation.~~

A.1

Relocated Item (R-19)

R.19

4.3 REACTOR COOLANT SYSTEM (RCS) TESTING

A. Reactor Coolant System Integrity Testing

Applicability

Applies to test requirements for Reactor Coolant System integrity.

Objective

To specify tests for Reactor Coolant System integrity after the system is closed following refueling, repair, replacement or modification.

Specification

a) The Reactor Coolant System shall be tested for leakage at normal operating pressure prior to plant startup following each refueling outage, in accordance with the requirements of ASME Section XI.

b) Testing of repairs, replacements or modifications for the Reactor Coolant System shall meet the requirements of ASME Section XI.

c) The Reactor Coolant System leak test temperature-pressure relationship shall be in accordance with the limits of Figure 4.3-1 for heatup for the first 13.3 EFPYs of operations. Figure 4.3-1 will be recalculated periodically. Allowable pressures during cooldown from the leak test temperature shall be in accordance with Figure 3.1-2.

Basis

Leak test of the Reactor Coolant System is required by the ASME Boiler and Pressure Vessel Code, Section XI, to ensure leak tightness of the system during operation. The test frequency and conditions are specified in the Code.

For repairs on components, the thorough non-destructive testing gives a very high degree of confidence in the integrity of the system, and will detect any significant defects in and near the new welds. In all cases, the leak test will assure leak tightness during normal operation.

The inservice leak test temperatures are shown on Figure 4.3-1. The temperatures are calculated in accordance with ASME Code Section III, Appendix G. This Code requires that a safety factor of 1.5 times the stress intensity factor caused by pressure be applied to the calculation.

For the first 13.3 effective full power years, it is predicted that the highest RT_{NDT} in the core region taken at the 1/4 thickness will be 214°F. The temperature determined by methods of ASME Code Section III for 1985 psig is 134°F above this RT_{NDT} and for 2485 psig (maximum) is 153°F above this RT_{NDT}. The minimum inservice leak test temperature requirements for periods up to 13.3 effective full power years are shown on Figure 4.3-1.

The heatup limits specified on the heatup curve, Figure 4.3-1, must not be exceeded while the reactor coolant system is being heated to the inservice leak test temperature. For cooldown from the leak test temperature, the limitations of Figure 3.1-2 must not be exceeded. Figures 4.3-1 and 3.1-2 are recalculated periodically, using methods discussed in the Basis for Specification 3.1.B and results of surveillance specimens, as covered in Specification 4.2.

Reference

1. FSAR, Section 4.

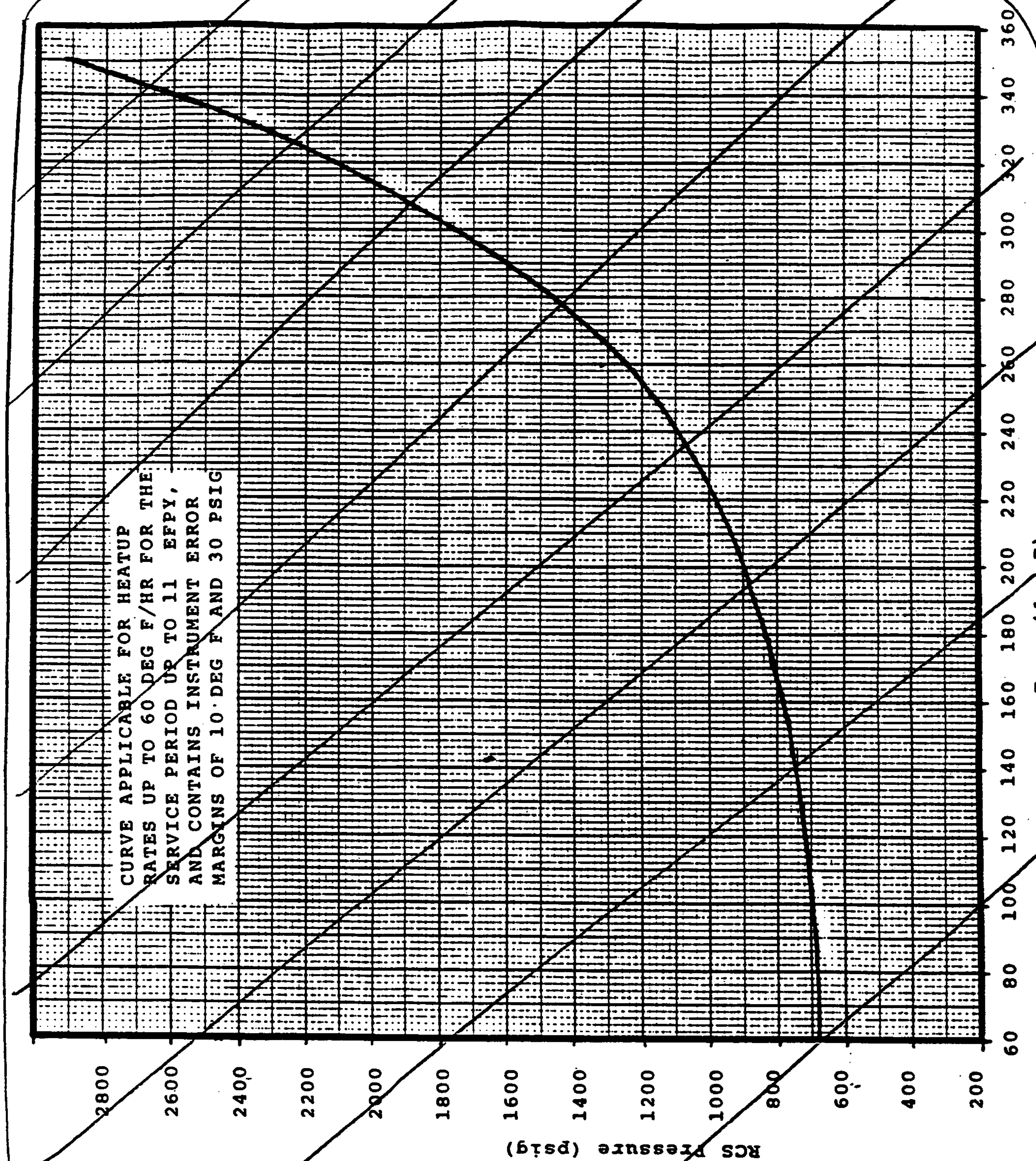
2. "Indian Point Unit 3 Final Report on Appendix G Reactor Vessel Pressure-Temperature Limits" ABB-Combustion Engineering, July 24, 1990

A.1

LA.1

FIGURE 4.3-1

Pressure/Temperature Limits for Hydrostatic Leak Test



MATERIAL PROPERTY BASIS

Controlling Material:	Plate Metal	RT_{NDT} INITIAL:	74°F
Copper Content:	0.24 wt. %	RT_{NDT} AFTER 11 EFPY:	1/4 T - 202°F
Phosphorous Content:	0.012 wt. %		3/4 T - 163°F

4.3 REACTOR COOLANT SYSTEM (RCS) TESTING

B. Reactor Coolant System Flow Calculation

Specification

precision heat balance A.5

SR 3.4.1.4 & Note

Once every 24 months, prior to exceeding 24 hours of continuous operation with THERMAL POWER ≥ 90% RTP, verify by flow calculation that RCS total flow rate is ≥ 375,600 gpm.

Basis

~~Measurement of RCS total flow rate by performance of a flow calculation once every 24 months verifies that the actual RCS flow rate is greater than or equal to the minimum required RCS flow rate.~~

~~The frequency of 24 months reflects the importance of verifying flow after a refueling outage when the core has been altered or steam generator tubes have been plugged, which may have caused an alteration of flow resistance.~~

~~This specification allows for placement of the unit in the best condition for performing the Surveillance Requirement. The specification allows the Surveillance Requirement to be performed within 24 hours after THERMAL POWER ≥ 90% RTP. This is appropriate because a flow calculation performed with the plant ≥ 90% RTP will ensure that instrument inaccuracies are consistent with those assumed in the accident analyses. The Surveillance shall be performed within 24 hours of continuous operation at or above 90% RTP.~~

A.1

Amendment No. ~~170~~, 175

4.4 CONTAINMENT TESTS

A2

~~Applicability~~

~~Applies to containment leakage.~~

~~Objective~~

~~To verify that potential leakage from the containment is maintained within acceptable values.~~

~~Specification~~

~~A~~ Integrated Leakage Rate

SR3.6.1.1 Perform required visual examinations and leakage rate testing, except for containment air lock testing, in accordance with the Containment Leakage Rate Testing Program.

Amendment No. 77, 98, 174

~~B. DELETED~~ A.1

C. Sensitive Leakage Rate

SEE RELOCATED CTS

Verify the leakage rate for the Containment Penetration and Weld Channel Pressurization System is ≤ 0.2 percent of the containment free volume per day when pressurized to ≥ 43 psig and the containment pressure is atmospheric. The testing shall be performed at intervals no greater than 3 years.

D. Air Lock Tests

SR 3.6.2.1

Perform required Containment Air Lock leak rate testing in accordance with the Containment Leakage Rate Testing Program.

Add SR 3.6.2.1, Note 1 — A.10

Add SR 3.6.2.1, Note 2 — A.9

Add SR 3.6.2.2 — M.3

R.6

C. Sensitive Leakage Rate

~~Verify the leakage rate for the Containment Penetration and Weld Channel Pressurization System is ≤ 0.2 percent of the containment free volume per day when pressurized to ≥ 43 psig and the containment pressure is atmospheric. The testing shall be performed at intervals no greater than 3 years.~~

D. Air Lock Tests

SEE ITS

Perform required Containment Air Lock leak rate testing in accordance with the Containment Leakage Rate Testing Program.

SEE ITS 5.15, Cont. Leak Rate, Test Prog

LA.1

E. Containment Isolation Valves

SR3.6.3.8 ~~1.~~ Verify the combined leakage rate for all containment bypass leakage paths, Table 4.4-1 lists required isolation valves, is ≤ 0.6La when pressurized ≥ Pa in accordance with the Containment Leakage Rate Testing Program.

SEE ITS 3.6.9

~~2.~~ Verify the leakage rate of water from the Isolation Valve Seal Water System is ≤ 14,700 cc/hr when pressurized ≥ 1.1 Pa, in accordance with the Containment Leakage Rate Testing Program.

~~3.~~ Verify the leakage rate of water into the containment from isolation valves sealed with the service water system is ≤ 0.36 gpm per fan cooler unit when pressurized ≥ 1.1 Pa, in accordance with the Containment Leakage Rate Testing Program.

Add SR 3.6.3.3 and Note

Add SR 3.6.3.4 and Note

M.3

Add SR 3.6.3.5

M.4

SEE ITS 5.15, Containment Leak Rate Test Program

E. Containment Isolation Valves

SEE ITS 3.6.3	1.	Verify the combined leakage rate for all containment bypass leakage paths, Table 4.4-1 lists required isolation valves, is ≤ 0.6La when pressurized ≥ Pa, in accordance with the Containment Leakage Rate Testing Program.
SR 3.6.9.5	~~2.~~	Verify the leakage rate of water from the Isolation Valve Seal Water System is ≤ 14,700 cc/hr when pressurized ≥ 1.1 Pa, in accordance with the Containment Leakage Rate Testing Program.
SEE CTS RELOCATED	3.	Verify the leakage rate of water into the containment from isolation valves sealed with the service water system is ≤ 0.36 gpm per fan cooler unit when pressurized ≥ 1.1 Pa, in accordance with the Containment Leakage Rate Testing Program.

Add SR 3.6.9.2
Add SR 3.6.9.4
Add SR 3.6.9.5

M.3

E. Containment Isolation Valves

SEE ITS 3.6.3 and 3.6.9

1. Verify the combined leakage rate for all containment bypass leakage paths, Table 4.4-1 lists required isolation valves, is ≤ 0.6La when pressurized ≥ Pa, in accordance with the Containment Leakage Rate Testing Program.

2. Verify the leakage rate of water from the Isolation Valve Seal Water System is ≤ 14,700 cc/hr when pressurized ≥ 1.1 Pa, in accordance with the Containment Leakage Rate Testing Program.

R-13

3. ~~Verify the leakage rate of water into the containment from isolation valves sealed with the service water system is ≤ 0.36 gpm per fan cooler unit when pressurized ≥ 1.1 Pa, in accordance with the Containment Leakage Rate Testing Program.~~ R.13

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I. Residual Heat Removal System

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1. Test

a. (1) The portion of the Residual Heat Removal System that is outside the containment shall be tested either by use in normal operation or hydrostatically tested at 350 psig at the interval specified below.

(2) The piping between the residual heat removal pumps suctions and the containment isolation valves in the residual heat removal pump suction line from the containment sump shall be hydrostatically tested at no less than 100 psig at the interval specified below.

b. Visual inspection shall be made for excessive leakage during these tests from components of the system. Any significant leakage shall be measured by collection and weighing or by another equivalent method.

2. Acceptance Criterion

The maximum allowable leakage from the Residual Heat Removal System components located outside of the containment shall not exceed two gallons per hour.

3. Corrective Action

Repairs or isolation shall be made as required to maintain leakage within the acceptance criterion.

4. Test Frequency

Tests of the Residual Heat Removal System shall be conducted at least once per 24 months.

Basis

The containment is designed for a pressure of 47 psig. (1) While the reactor is operating, the internal environment of the containment will be air at essentially atmospheric pressure and an average maximum temperature of approximately 130°F. The Design Basis Accidents (DBA) that represent a challenge to the containment structure are a Loss of Coolant Accident (LOCA) and a Main Steam Line Break (MSLB). The limiting calculated peak containment pressure of 42.40 psig is a result of the MSLB (7), which is less than the stated design pressure of 47 psig. In addition, DBA analyses demonstrate that the calculated peak containment temperature will remain less than the Equipment Qualification (EQ) envelope temperature of 290 degrees F.

The containment structure is designed to contain, within established leakage limits, radioactive material that may be released from the reactor core following a DBA. The containment was designed with an allowable leakage rate of 0.1 weight percent of containment air per day. This leakage rate, used to evaluate offsite doses resulting from DBAs is defined in 10CFR 50 Appendix B as L_a; the maximum allowable containment leakage rate at the calculated peak containment internal pressure (P_a) resulting from the limiting DBA. The allowable leakage rate represented by L_a forms the basis for the acceptance criteria imposed on all containment leakage rate testing performed in accordance with the program required by Technical Specification 6.14. The minimum test pressure for this program, based on the current value of P_a is 42.40 psig. Analyses which established the previous minimum test pressure of 42.42 psig were performed to support an increase of the ultimate heat sink temperature. (4) The conclusions of that analysis regarding heat sink temperature, as incorporated by Technical Specification Amendment 98, remain valid.

Prior to initial operation, the containment was strength-tested at 54 psig and was leak-tested. The acceptance criterion for this pre-operational leakage rate test was established as 0.075 W/o (.75 L_a) per 24 hours at 40.6 psig and 263°F, which were the peak accident pressure and temperature conditions at that time. This leakage rate is consistent with the construction of the containment, (2) which is equipped with a Weld Channel and Penetration Pressurization System for continuously pressurizing the containment penetrations and the channels over certain containment liner welds. These channels were independently leak-tested during construction.

The safety analysis has been performed on the basis of a leakage rate of 0.10 W/o per day for 24 hours. With this leakage rate and with minimum containment engineered safeguards operating, the public exposure would be well below 10CFR100 values in the event of the design basis accident. (3)

Maintaining the containment operable requires compliance with the visual examinations and leakage rate test requirements of the Containment Leakage Rate Testing Program. Failure to meet air lock leakage limits specified in surveillance requirement 4.4.D does not invalidate the acceptability of these overall leakage determinations unless their contribution to overall Type A, B, and C leakage causes that to exceed limits. As left leakage

Basis

The containment is designed for a pressure of 47 psig. [1] While the reactor is operating, the internal environment of the containment will be air at essentially atmospheric pressure and an average maximum temperature of approximately 130°F. The Design Basis Accidents (DBA) that represent a challenge to the containment structure are a Loss of Coolant Accident (LOCA) and a Main Steam Line Break (MSLB). The limiting calculated peak containment pressure of 42.40 psig is a result of the MSLB [7], which is less than the stated design pressure of 47 psig. In addition, DBA analyses demonstrate that the calculated peak containment temperature will remain less than the Equipment Qualification (EQ) envelope temperature of 290 degrees F.

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The safety analysis has been performed on the basis of a leakage rate of 0.10 W/o per day for 24 hours. With this leakage rate and with minimum containment engineered safeguards operating, the public exposure would be well below 10CFR100 values in the event of the design basis accident. [3]

Maintaining the containment operable requires compliance with the visual examinations and leakage rate test requirements of the Containment Leakage Rate Testing Program. Failure to meet air lock leakage limits specified in surveillance requirement 4.4.D does not invalidate the acceptability of these overall leakage determinations unless their contribution to overall Type A, B, and C leakage causes that to exceed limits. As left leakage

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prior to the first startup after performing a required 10 CFR 50, Appendix J, leakage test is required to be <0.6 L_a for combined Type B and C leakage, and < 0.75 L_a for overall Type A leakage. At all other times between required leakage rate tests, the acceptance criteria is based on an overall Type A leakage limit of ≤ 1.0 L_a. At ≤ 1.0 L_a the offsite dose consequences are bounded by the assumptions of the safety analysis. Surveillance requirement frequencies are as required by the Containment Leakage Rate Testing Program. Thus, Specification 1.12 (which allows Frequency extensions) does not apply. These periodic testing requirements verify that the containment leakage rate does not exceed the leakage rate assumed in the safety analysis.

The Weld Channel and Containment Penetration Pressurization System (WCCPPS)[5] is in service continuously to monitor leakage from potential leak paths such as the containment personnel lock seals and weld channels, containment penetrations, containment liner weld channels, double-gasketed seals and spaces between certain containment isolation valves and personnel door locks. A leak would be expected to build up slowly and would, therefore, be noted before design limits are exceeded. Remedial action can be taken before the limit is reached. The sensitive leakage rate test of the WCCPPS demonstrates that pressurized containment penetrations and liner inner weld seams are within a leakage acceptance criteria that will allow the air receivers and the standby source of gas pressure, nitrogen cylinders, to provide a 24 hour supply of gas to the system. The WCCPPS is not credited for limiting containment isolation valve leakage and the sensitivity test is not used for demonstrating compliance with containment isolation valve leakage criteria. The frequency of the sensitive leakage test reflects an extension of 25 percent from the 24 month refueling cycle and, therefore, Specification 1.12 (which allows Frequency extensions) does not apply[10].

Maintaining containment air locks operable requires compliance with the leakage rate test requirements of the Containment Leakage Rate Testing Program. The surveillance requirement reflects the leakage rate testing requirements with regard to air lock leakage (Type B leakage tests). The acceptance criteria were established during air lock and containment OPERABILITY testing. The periodic testing requirements verify that the air lock leakage does not exceed the allowed fraction of the overall containment leakage rate. The Frequency is required by the Containment Leakage Rate Testing Program. Thus, Specification 1.12 (which allows Frequency extensions) does not apply. During normal plant operation, containment personnel lock door seals are continuously pressurized after each closure by the WCCPPS. Whenever containment integrity is required, verification is made that seals repressurize properly upon closure of an air lock door. The verification meets the intent of the 10 CFR 50 Appendix J requirements.[8]

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~~The containment isolation valve surveillance requirement ensures that the combined leakage rate of all containment bypass leakage paths is less than or equal to the specified leakage rate. This provides assurance that the assumptions in the safety analysis are met. The leakage rate of each bypass leakage path is assumed to be the maximum pathway leakage (leakage through the worse of the two isolation valves, and, when pressurizing between valves, the total leakage of all the valves being tested) unless the penetration is isolated by use of one closed and de-activated automatic valve, closed manual valve, or blind flange. In this case, the leakage rate of the isolated bypass leakage path is assumed to be the actual pathway leakage through the isolation device. If both isolation valves in the penetration are closed, the actual leakage rate is the lesser leakage rate of the two valves. The Frequency is required by the Containment Leakage Rate Testing Program. This surveillance requirement simply imposes additional acceptance criteria. The service water lines to the containment fan cooler units and the lines supplied water by the Isolation Valve Seal Water System (IVSWS)[6] have containment isolation valves that are hydrostatically tested. Surveillance of hydrostatically tested lines provides assurance that the calculation assumptions of offsite doses are met. The Frequency is required by the Containment Leakage Rate Testing Program. Sufficient water is available in the Isolation Valve Seal Water System, Primary Water System, Service Water System, Residual Heat Removal System, and the City Water System to assure a sealing function for at least 30 days. The leakage limit for the Isolation Valve Seal Water System is consistent with the design capacity of the Isolation Valve Seal Water supply tank. The seal water provided by these systems is credited with limiting containment leakage (the measured leakage is not considered part of the allowable containment leakage).~~

~~The 350 psig test pressure, achieved either by normal Residual Heat Removal System operation or hydrostatic testing, gives an adequate margin over the highest pressure within the system after a design basis accident. Similarly, the hydrostatic test pressure for the containment sump return line of 100 psig gives an adequate margin over the highest pressure within the line after a design basis accident. A recirculation system leakage of 2 gal./hr. will limit off-site exposures due to leakage to insignificant levels relative to those calculated for leakage directly from the containment in the design basis accident.~~

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The maximum permissible inleakage rate from the containment isolation valves sealed with service water for the full 12-month period of post accident recirculation without flooding the internal recirculation pumps is 0.36 gpm per fan cooler.

REFERENCES

(1) FSAR - Section 5
(2) FSAR - Section 5.1.7
(3) FSAR - 14.3.5
(4) WCAP - 12269 Rev. 1, "Containment Margin Improvement Analysis for IP-3 Unit 3"
(5) FSAR - Section 6.6
(6) FSAR - Section 6.5
(7) Nuclear Safety Evaluation 98-3-013-MULT, "Integrated Safety Evaluation of 24-Month Cycle Instrument Channel Uncertainties," Revision 0, dated March 3, 1998.
(8) SECL-96-103, Indian Point Unit 3 Safety Evaluation of 24-Month Fuel Cycle Phase I Instrument Channel Uncertainties, June 1996
(9) Indian Point 3 Safety Evaluation Report, Supplement 2, December 1975.
(10) NRC Safety Evaluation Related to Amendment 129 to Operating License DPR-64.

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(1) FSAR - Section 5
(2) FSAR - Section 5.1.7
(3) FSAR - 14.3.5
(4) WCAP - 12269 Rev. 1, "Containment Margin Improvement Analysis for IP-3 Unit 3"
(5) FSAR - Section 6.6
(6) FSAR - Section 6.5
(7) Nuclear Safety Evaluation 98-3-013-MULT, "Integrated Safety Evaluation of 24-Month Cycle Instrument Channel Uncertainties," Revision 0, dated March 3, 1998.
(8) SECL-96-103, Indian Point Unit 3 Safety Evaluation of 24-Month Fuel Cycle Phase I Instrument Channel Uncertainties, June 1996
(9) Indian Point 3 Safety Evaluation Report, Supplement 2, December 1975.
(10) NRC Safety Evaluation Related to Amendment 129 to Operating License DPR-64.

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TABLE 4.4-1 (Page 1 of 7)

CONTAINMENT ISOLATION VALVES

Valve No.	Penetration Number(1)	Test Fluid(2)	Minimum Test Pressure (PSIG)(8)
RC-AOV-549	1	Water(4)	47
RC-AOV-548	1	Water(4)	47
RC-518	2	Gas	43
RC-AOV-550	2	Gas	43
RC-AOV-552	3	Water(4)	47
RC-AOV-519	3	Water(4)	47
AC-741	4	Water(5)	47(3)
AC-MOV-744	4	Nitrogen(4)	43(3)
SI-MOV-888A	5	Nitrogen(4)	43
SI-MOV-888B	5	Nitrogen(4)	43
AC-AOV-958	5	Nitrogen(4)	43
SP-AOV-959	5	Nitrogen(4)	43
SP-990C	5	Nitrogen(4)	43
AC-MOV-1870	5	Nitrogen(4)	43
AC-MOV-743	5	Nitrogen(4)	43
AC-732	6	Nitrogen(4)	43(3)
SI-MOV-885A	7	Water(5)	47
SI-MOV-885B	7	Water(5)	47
CH-AOV-201	8	Water(4)	47
CH-AOV-202	8	Water(4)	47
CH-MOV-205	9	Water(4)	47
CH-MOV-226	9	Water(4)	47
CH-227	9	Water(4)	47
CH-MOV-250A	10	Water(4)	47
CH-MOV-441	10	Water(4)	47
CH-MOV-250B	10	Water(4)	47
CH-MOV-442	10	Water(4)	47
CH-MOV-250C	10	Water(4)	47

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TABLE 4.4-1 (Page 2 of 7)

CONTAINMENT ISOLATION VALVES

Valve No.	Penetration Number(1)	Test Fluid(2)	Minimum Test Pressure (PSIG)(3)
CH-MOV-443	10	Water(4)	47
CH-MOV-280D	10	Water(4)	47
CH-MOV-444	10	Water(4)	47
CH-MOV-222	11	Water(4)	47
SP-AOV-956E	12	Water(4)	47
SP-AOV-956F	12	Water(4)	47
SI-869A	14	Water(4)	47
SI-867A	14	Gas	43
SI-878A	14	Gas	43
SI-869B	14	Water(4)	47
SI-867B	14	Gas	43
SI-878B	14	Gas	43
SI-MOV-1835A	15	Nitrogen(4)	43
SI-MOV-1835B	15	Nitrogen(4)	43
SI-MOV-851A	15	Water(4)	47
SI-MOV-850A	15	Water(4)	47
SI-MOV-850C	15	Water(4)	47
SI-859A	16	Water(4)	47
SI-859C	16	Water(4)	47
NNE-1610	17	Gas	43
NNE-AOV-863	17	Gas	43
SP-AOV-956G	18	Water(4)	47
SP-AOV-956H	18	Water(4)	47
WD-AOV-1786	19	Water(4)	47
WD-AOV-1787	19	Water(4)	47

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TABLE 4.4-1 (Page 3 of 7)

CONTAINMENT ISOLATION VALVES

Valve No.	Penetration Number (1)	Test Fluid (2)	Minimum Test Pressure (PSIG) (8)
WD-AOV-1610	19	Gas	43
WD-1616	19	Gas	43
WD-AOV-1788	20	Water (4)	47
WD-AOV-1789	20	Water (4)	47
WD-AOV-1702	21	Water (4)	47
WD-AOV-1705	21	Water (4)	47
AC-MOV-797	22	Water (4)	47
AC-MOV-769	22	Water (4)	47
AC-MOV-784	23	Water (4)	47
AC-MOV-786	23	Water (4)	47
AC-FCV-625	24	Water (4)	47
AC-MOV-789	24	Water (4)	47
AC-AOV-791	29	Water (4)	47
AC-AOV-798	29	Water (4)	47
AC-AOV-796	30	Water (4)	47
AC-AOV-793	30	Water (4)	47
WD-AOV-1728	31	Water (4)	47
WD-AOV-1723	31	Water (4)	47
VS-PCV-1234	32	Gas (7)	43
VS-PCV-1235	32	Gas (7)	43
VS-PCV-1236	33	Gas (7)	43
VS-PCV-1237	33	Gas (7)	43
CA-PCV-1229	34	Gas (7)	43
CA-PCV-1230	34	Gas (7)	43
BD-PCV-1215	37	Water (4)	47
BD-PCV-1215A	37	Water (4)	47
BD-PCV-1214	37	Water (4)	47
BD-PCV-1214A	37	Water (4)	47
BD-PCV-1216	37	Water (4)	47
BD-PCV-1216A	37	Water (4)	47
BD-PCV-1217	37	Water (4)	47
BD-PCV-1217A	37	Water (4)	47

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TABLE 4.4-1 (Page 4 of 7)

CONTAINMENT ISOLATION VALVES

Valve No.	Penetration Number(1)	Test Fluid(2)	Minimum Test Pressure(PSIG)(8)
BD-PCV-1224	38	Water(4)	47
BD-PCV-1224A	38	Water(4)	47
BD-PCV-1223	38	Water(4)	47
BD-PCV-1223A	38	Water(4)	47
BD-PCV-1225	38	Water(4)	47
BD-PCV-1225A	38	Water(4)	47
BD-PCV-1226	38	Water(4)	47
BD-PCV-1226A	38	Water(4)	47
SWN-41-1	39	Water(6)	47
SWN-43-1	39	Water(6)	47
SWN-42-1	39	Water(6)	47
SWN-41-2	39	Water(6)	47
SWN-43-2	39	Water(6)	47
SWN-42-2	39	Water(6)	47
SWN-41-3	39	Water(6)	47
SWN-43-3	39	Water(6)	47
SWN-42-3	39	Water(6)	47
SWN-41-4	39	Water(6)	47
SWN-43-4	39	Water(6)	47
SWN-42-4	39	Water(6)	47
SWN-41-5	39	Water(6)	47
SWN-43-5	39	Water(6)	47
SWN-42-5	39	Water(6)	47
SWN-44-1	40	Water(6)	47
SWN-51-1	40	Water(6)	47
SWN-44-2	40	Water(6)	47
SWN-51-2	40	Water(6)	47
SWN-44-3	40	Water(6)	47
SWN-51-3	40	Water(6)	47
SWN-44-4	40	Water(6)	47
SWN-51-4	40	Water(6)	47

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~~TABLE 4.4-1~~ (Page 5 of 7)

CONTAINMENT ISOLATION VALVES			
Valve No.	Penetration Number[1]	Test Fluid[2]	Minimum Test Pressure (PSIG)[8]
SWN-44-5	40	Water[6]	47
SWN-51-5	40	Water[6]	47
SWN-71-1	40	Water[6]	47
SWN-71-2	40	Water[6]	47
SWN-71-3	40	Water[6]	47
SWN-71-4	40	Water[6]	47
SWN-71-5	40	Water[6]	47
SA-24-1	41	Water[4]	47
SA-24-2	41	Water[4]	47
VS-FCV-1170	48	Gas[7]	43
VS-FCV-1171	48	Gas[7]	43
VS-FCV-1172	49	Gas[7]	43
VS-FCV-1173	49	Gas[7]	43
VS-FCV-1190	50	Gas[7]	43
VS-FCV-1191	50	Gas[7]	43
VS-FCV-1192	50	Gas[7]	43
SP-MOV-990A	51	Nitrogen[4]	43
SP-MOV-990B	51	Nitrogen[4]	43
SP-AOV-956A	52	Water[4]	47
SP-AOV-956B	52	Water[4]	47
SP-AOV-956C	53	Water[4]	47
SP-AOV-956D	53	Water[4]	47
SI-1814A	54	Gas	43
SI-1814B	55	Gas	43
SI-1814C	56	Gas	43
SP-SOV-506	57	Gas[7]	43
SP-SOV-507	57	Gas[7]	43

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TABLE 4.4-1 (Page 6 of 7)

CONTAINMENT ISOLATION VALVES

Valve No.	Penetration Number[1]	Test Fluid[2]	Minimum Test Pressure (PSIG)[8]
SP-SOV-508	57	Gas[7]	43
SP-SOV-509	57	Gas[7]	43
SP-SOV-510	57	Gas[7]	43
SP-SOV-511	57	Gas[7]	43
SP-SOV-512	57	Gas[7]	43
SP-SOV-513	57	Gas[7]	43
SP-SOV-514	57	Gas[7]	43
SP-SOV-515	57	Gas[7]	43
SP-SOV-516	57	Gas[7]	43
IA-39	64	Gas	43
IA-PCV-1228	64	Gas	43
PS-7	65	Gas[7]	43
PS-10	65	Gas[7]	43
PS-8	65	Gas[7]	43
PS-9	65	Gas[7]	43
CB-1	69	Gas	43
CB-2	69	Gas	43
CB-3	69	Gas[7]	43
CB-4	69	Gas[7]	43
CB-5	68	Gas	43
CB-6	68	Gas	43
CB-7	68	Gas[7]	43
CB-8	68	Gas[7]	43
DW-AOV-1	70	Water[4]	47
DW-AOV-2	70	Water[4]	47

LA.1.

TABLE 4.4-1 (Page 7 of 7)

CONTAINMENT ISOLATION VALVES

NOTES:

1. Reference: FSAR Table 5.2-1, Penetration No.
2. Gas Test Fluid indicates either nitrogen or air as test medium.
3. Testable only when at cold shutdown.
4. Isolation Valve Seal Water System.
5. Sealed by Residual Heat Removal System fluid.
6. Sealed by Service Water System.
7. Sealed by Weld Channel and Penetration Pressurization System.
8. The minimum test pressure may be reduced by 2 psig until the current requirements associated with the Boron Injection Tank are removed (see Tech Spec 3.3.A.3.b).

4.5 TESTS FOR ENGINEERED SAFETY FEATURES AND AIR FILTRATION SYSTEMS

A.2

~~Applicability~~

~~Applies to testing of the Safety Injection System, the Containment Spray System, the Hydrogen Recombiner System, and the Air Filtration Systems.~~

~~Objective~~

~~To verify that the subject systems will respond promptly and perform their design functions, if required.~~

Specification

A. SYSTEM TESTS

T 3.3.1-1, #16
SR 3.3.1.4

1. Safety Injection System

A..

a. System tests shall be performed at least once per 24 months*. With the Reactor Coolant System pressure less than or equal to 350 psig and temperature less than or equal to 350°F, a test safety injection signal will be applied to initiate operation of the system. The safety injection and residual heat removal pumps are made inoperable for this test.

SEE ITS 3.5.2

b. The test will be considered satisfactory if control board indication and visual observations indicate that all components have received the safety injection signal in the proper sequence and timing, that is, the appropriate pump breakers shall have opened and closed, and the appropriate valves shall have completed their travel.

c. Conduct a flow test of the high head safety injection system after any modification is made to either its piping and/or valve arrangement.

d. Verify that the mechanical stops on Valves 856 A, C, D, E, F, H, J and K are set at the position measured and recorded during the most recent ECCS operational flow test or flow tests performed in accordance with (c) above. This surveillance procedure shall be performed following any maintenance on these valves or their associated motor operators and at a convenient outage if the position of the mechanical stops have not been verified in the preceding three months.

* The time delay relays will be tested at intervals no greater than 22.5 months (18 months + 25%).

Amendment No. ~~123~~, 142

4.5 TESTS FOR ENGINEERED SAFETY FEATURES AND AIR FILTRATION SYSTEMS

A.2

~~Applicability~~

~~Applies to testing of the Safety Injection System, the Containment Spray System, the Hydrogen Recombiner System, and the Air Filtration Systems.~~

~~Objective~~

~~To verify that the subject systems will respond promptly and perform their design functions, if required.~~

Specification

T 3.3.2-1, #1a

A. SYSTEM TESTS

1. Safety Injection System

A.3

SR 3.3.2.6

a. System tests shall be performed at least once per 24 months*. With the Reactor Coolant System pressure less than or equal to 350 psig and temperature less than or equal to 350°F, a test safety injection signal will be applied to initiate operation of the system. The safety injection and residual heat removal pumps are made inoperable for this test.

b. The test will be considered satisfactory if control board indication and visual observations indicate that all components have received the safety injection signal in the proper sequence and timing, that is, the appropriate pump breakers shall have opened and closed, and the appropriate valves shall have completed their travel.

SEE ITS 3.5.2

c. Conduct a flow test of the high head safety injection system after any modification is made to either its piping and/or valve arrangement.

d. Verify that the mechanical stops on Valves 856 A, C, D, E, F, H, J and K are set at the position measured and recorded during the most recent ECCS operational flow test or flow tests performed in accordance with (c) above. This surveillance procedure shall be performed following any maintenance on these valves or their associated motor operators and at a convenient outage if the position of the mechanical stops have not been verified in the preceding three months.

* The time delay relays will be tested at intervals no greater than 22.5 months (18 months + 25%).

4.5 TESTS FOR ENGINEERED SAFETY FEATURES AND AIR FILTRATION SYSTEMS

A.2

~~Applicability~~

~~Applies to testing of the Safety Injection System, the Containment Spray System, the Hydrogen Recombiner System, and the Air Filtration Systems.~~

~~Objective~~

~~To verify that the subject systems will respond promptly and perform their design functions, if required.~~

Specification

A. SYSTEM TESTS

1. Safety Injection System

SR3.3.6.4

a. System tests shall be performed at least once per 24 months*. With the Reactor Coolant System pressure less than or equal to 350 psig and temperature less than or equal to 350°F, a test safety injection signal will be applied to initiate operation of the system. The safety injection and residual heat removal pumps are made inoperable for this test.

SEE CTS MASTER MARKUP

b. The test will be considered satisfactory if control board indication and visual observations indicate that all components have received the safety injection signal in the proper sequence and timing, that is, the appropriate pump breakers shall have opened and closed, and the appropriate valves shall have completed their travel.

c. Conduct a flow test of the high head safety injection system after any modification is made to either its piping and/or valve arrangement.

d. Verify that the mechanical stops on Valves 856 A, C, D, E, F, H, J and K are set at the position measured and recorded during the most recent ECCS operational flow test or flow tests performed in accordance with (c) above. This surveillance procedure shall be performed following any maintenance on these valves or their associated motor operators and at a convenient outage if the position of the mechanical stops have not been verified in the preceding three months.

* The time delay relays will be tested at intervals no greater than 22.5 months (18 months + 25%).

4.5 TESTS FOR ENGINEERED SAFETY FEATURES AND AIR FILTRATION SYSTEMS

A.2

~~Applicability~~

~~Applies to testing of the Safety Injection System, the Containment Spray System, the Hydrogen Recombiner System, and the Air Filtration Systems.~~

~~Objective~~

~~To verify that the subject systems will respond promptly and perform their design functions, if required.~~

Specification

A. SYSTEM TESTS

1. Safety Injection System

A.3

or actual

SR 3.5.2.4
SR 3.5.2.5

a. System tests shall be performed at least once per 24 months*. ~~With the Reactor Coolant System pressure less than or equal to 350 psig and temperature less than or equal to 350°F,~~ a test safety injection signal will be applied to initiate operation of the system. ~~The safety injection and residual heat removal pumps are made inoperable for this test.~~ LA.3 A.5

SR 3.5.2.4
SR 3.5.2.5

b. The test will be considered satisfactory if ~~control board indication and visual observations indicate that all components have received the safety injection signal in the proper sequence and timing, that is,~~ the appropriate pump ~~breakers shall have opened and closed,~~ starts and the appropriate valves shall have completed their travel. LA.3

~~c.~~ ~~Conduct a flow test of the high head safety injection system after any modification is made to either its piping and/or valve arrangement.~~ A.6

SR 3.5.2.6

~~d.~~ Verify that the mechanical stops on Valves 856 A, C, D, E, F, H, J and K are set ~~at the position measured and recorded during the most recent ECCS operational flow test or flow tests performed in accordance with (c) above.~~ ~~This surveillance procedure shall be performed following any maintenance on these valves or their associated motor operators~~ and at a convenient outage if the position of the mechanical stops have not been verified in the preceding three months. LA.3 A.6 L.5

SEE ITS 3.8.1 * The time delay relays will be tested at intervals no greater than 22.5 months (18 months + 25%).

Amendment No. ~~123~~, 142

Add SR 3.5.2.7 M.2

A.1

A.2

4.5 TESTS FOR ENGINEERED SAFETY FEATURES AND AIR FILTRATION SYSTEMS

~~Applicability~~

~~Applies to testing of the Safety Injection System, the Containment Spray System, the Hydrogen Recombiner System, and the Air Filtration Systems.~~

~~Objective~~

~~To verify that the subject systems will respond promptly and perform their design functions, if required.~~

~~Specification~~

A. SYSTEM TESTS

1. Safety Injection System

LCO 3.5.3

a. System tests shall be performed at least once per 24 months. With the Reactor Coolant System pressure less than or equal to 350 psig and temperature less than or equal to 350°F, a test safety injection signal will be applied to initiate operation of the system. The safety injection and residual heat removal pumps are made inoperable for this test. L3

b. The test will be considered satisfactory if control board indication and visual observations indicate that all components have received the safety injection signal in the proper sequence and timing, that is, the appropriate pump breakers shall have opened and closed, and the appropriate valves shall have completed their travel. L3

SEE ITS 3.5.2

c. Conduct a flow test of the high head safety injection system after any modification is made to either its piping and/or valve arrangement.

d. Verify that the mechanical stops on Valves 856 A, C, D, E, F, H, J and K are set at the position measured and recorded during the most recent ECCS operational flow test or flow tests performed in accordance with (c) above. This surveillance procedure shall be performed following any maintenance on these valves or their associated motor operators and at a convenient outage if the position of the mechanical stops have not been verified in the preceding three months.

SEE ITS 3.8.1

The time delay relays will be tested at intervals no greater than 22.5 months (18 months + 25%).

4.5 TESTS FOR ENGINEERED SAFETY FEATURES AND AIR FILTRATION SYSTEMS

A.2

~~Applicability~~

~~Applies to testing of the Safety Injection System, the Containment Spray System, the Hydrogen Recombiner System, and the Air Filtration Systems.~~

~~Objective~~

~~To verify that the subject systems will respond promptly and perform their design functions, if required.~~

Specification

A. SYSTEM TESTS

SEE ITS 3.5.2

1. Safety Injection System

a. System tests shall be performed at least once per 24 months*. With the Reactor Coolant System pressure less than or equal to 350 psig and temperature less than or equal to 350°F, a test safety injection signal will be applied to initiate operation of the system. The safety injection and residual heat removal pumps are made inoperable for this test.

b. The test will be considered satisfactory if control board indication and visual observations indicate that all components have received the safety injection signal in the proper sequence and timing, that is, the appropriate pump breakers shall have opened and closed, and the appropriate valves shall have completed their travel.

c. Conduct a flow test of the high head safety injection system after any modification is made to either its piping and/or valve arrangement.

d. Verify that the mechanical stops on Valves 856 A, C, D, E, F, H, J and K are set at the position measured and recorded during the most recent ECCS operational flow test or flow tests performed in accordance with (c) above. This surveillance procedure shall be performed following any maintenance on these valves or their associated motor operators and at a convenient outage if the position of the mechanical stops have not been verified in the preceding three months.

SR 3.8.1.11 * The time delay relays will be tested at intervals no greater than 22.5 months (18 months + 25%). L.6

Add note to SR 3.8.1.11

Amendment No. ~~123~~, 142

2. Containment Spray System

SR 3.3.2.6

A.10

a. System tests shall be performed at least once per 24 months. ~~The tests shall be performed with the isolation valves in~~ the spray supply lines at the containment and the spray additive tank isolation valves blocked closed. Operation of the system is initiated by tripping the normal actuation instrumentation.

b. The spray nozzles shall be checked for proper functioning at least every five years.

SEE ITS MASTER MARKUP

c. The tests will be considered satisfactory if visual observations indicate all components have operated satisfactorily.

3. Containment Hydrogen Monitoring Systems

a. Containment hydrogen monitoring system tests shall be performed at intervals no greater than six months. The tests shall include drawing a sample from the fan cooler units.

b. The above tests will be considered satisfactory if visual observations and control panel indication indicate that all components have operated satisfactorily.

Amendment No. 101, 115, 125, 129, 172, TSCR 98-043

2. Containment Spray System

SR 3.3.6.4

a. System tests shall be performed at least once per 24 months. The tests shall be performed with the isolation valves in the spray supply lines at the containment and the spray additive tank isolation valves blocked closed. Operation of the system is initiated by tripping the normal actuation instrumentation.

b. The spray nozzles shall be checked for proper functioning at least every five years.

SEE CTS MASTER MARKUP

c. The tests will be considered satisfactory if visual observations indicate all components have operated satisfactorily.

3. Containment Hydrogen Monitoring Systems

a. Containment hydrogen monitoring system tests shall be performed at intervals no greater than six months. The tests shall include drawing a sample from the fan cooler units.

b. The above tests will be considered satisfactory if visual observations and control panel indication indicate that all components have operated satisfactorily.

Amendment No. 101, 115, 125, 129, 172, TSCR 98-043

2. Containment Spray System

SR 3.6.6.5 a. System tests shall be performed at least once per 24 months. ~~The tests shall be performed with the isolation valves in the spray supply lines at the containment and the spray additive tank isolation valves blocked closed.~~ Operation of

SR 3.6.6.6 the system is initiated by ~~tripping the normal actuation instrumentation~~ actual or simulated A

SR 3.6.6.9 b. The spray nozzles shall be checked for proper functioning at least every ~~five~~ 10 years. L

c. ~~The tests will be considered satisfactory if visual observations indicate all components have operated satisfactorily.~~ A.8

3. Containment Hydrogen Monitoring Systems

SEE ITS 3.3.3

a. Containment hydrogen monitoring system tests shall be performed at intervals no greater than six months. The tests shall include drawing a sample from the fan cooler units.

b. The above tests will be considered satisfactory if visual observations and control panel indication indicate that all components have operated satisfactorily.

Add SR 3.6.6.1 M.3

Add SR 3.6.6.2 M.4

Add SR 3.6.6.3 M.5

2. Containment Spray System

SR 3.6.7.4 ~~a.~~ System tests shall be performed at least once per 24 months. ~~The tests shall be performed with the isolation valves in the spray supply lines at the containment and the spray additive tank isolation valves blocked closed.~~ Operation of the system is initiated by ~~tripping the normal~~ actual or simulated actuation instrumentation. A.5 A.4

SEE ITS 3.6.6 b. The spray nozzles shall be checked for proper functioning at least every five years.

SR 3.6.7.4 c. ~~The tests will be considered satisfactory if visual observations indicate all components have operated satisfactorily.~~ A.5

3. Containment Hydrogen Monitoring Systems

SEE ITS 3.3.3

a. Containment hydrogen monitoring system tests shall be performed at intervals no greater than six months. The tests shall include drawing a sample from the fan cooler units.

b. The above tests will be considered satisfactory if visual observations and control panel indication indicate that all components have operated satisfactorily.

Add SR 3.6.7.1 M.1

Add SR 3.6.7.5 M.2

Amendment No. ~~101~~, ~~115~~, ~~125~~, ~~129~~, ~~172~~, TSCR 98-043

Add SR 3.6.6.8

A.6

4. Containment Air Filtration System

SEE ITS 5.5.10

a. Visual inspection of the filter installations shall be performed in accordance with ANSI N 510 (1975) every six months for the first two years and at least once per 24 months thereafter, or at any time fire, chemical releases or work done on the filters could alter their integrity.

b. At least once per 24 months, the following conditions shall be demonstrated before the system can be considered operable:

(1) The pressure drop across the combined HEPA filters and charcoal adsorber banks is less than 6 inches of water at ambient conditions and accident design flow rates.

(2) Using either direct or indirect measurements, the flow rate of the system fans shall be shown to be at least 90% of the accident design flow rate.

SR 3.6.6.7

(3) The charcoal filter isolation valves shall be tested to verify operability. starts automatically on simul or act signal — M.

SEE ITS 5.5.10

c. At least once per 24 months or at any time fire, chemical releases or work done on the filters could alter their integrity or after every 720 hours of charcoal adsorber use since the last test, the following conditions shall be demonstrated before the system can be considered operable:

(1) Impregnated activated charcoal from each of the five units shall have a methyl iodine removal efficiency $\geq$ 85% $\pm$ 20% of the accident design flow rate, 5 to 15 mg/m^3 inlet methyl iodine concentration, $\geq$ 95% relative humidity and $\geq$ 250°F. In addition, ignition shall not occur below 300°F.

(2) A halogenated hydrocarbon (freon) test on charcoal adsorbers at $\pm$ 20% of the accident design flow rate and ambient conditions shall show $\geq$ 99% halogenated hydrocarbon removal.

(3) A locally generated DOP* test of the HEPA filters at $\pm$ 20% of the accident design flow rate and ambient conditions shall show $\geq$ 99% DOP removal.

*Dioctylphthalate Particles

Fan Cooler Units — A.4

4. Containment ~~Air Filtration System~~ — Section C.5.a of R.G.1.52, Rev 2

5.5.10.a 5.5.10.b ~~a.~~ Visual inspection of the filter installations shall be performed in accordance with ~~ANSI N 510 (1975) every six months for the first two years and at least once per 24 months thereafter, or at any time fire, chemical releases or work done on the filters could alter their integrity.~~ — M.1 — A.3

5.5.10.d

b. At least once per 24 months, the following conditions shall be demonstrated before the system can be considered operable:

(1) The pressure drop across the combined HEPA filters, pre filters (if installed), and charcoal adsorber banks is less than 6 inches of water at ambient conditions and accident design flow rates. — A.3

(2) ~~Using either direct or indirect measurements,~~ the flow rate of the system fans shall be shown to be at least 90% of the accident design flow rate. — A.7

SEE ITS 3.6.6

(3) The charcoal filter isolation valves shall be tested to verify operability.

5.5.10 c. At least once per 24 months or at any time ~~fire,~~ significant painting, chemical releases, or work done on the filters could alter their integrity or after every 720 hours of charcoal adsorber use since the last test, the following conditions shall be demonstrated before the system can be considered operable: when in operation — M.2 — M.3 — A.6

5.5.10.c (1) Impregnated activated charcoal from each of the five units shall have a methyl iodine removal efficiency ≥ 85% ± 20% of the accident design flow rate, 5 to 15 mg/m^3 inlet methyl iodine concentration, ≥ 95% relative humidity and ≥ 250°F. In addition, ignition shall not occur below 300°F. — LA.1

5.5.10.b ~~(2)~~ A ~~halogenated hydrocarbon~~ (freon) test on charcoal adsorbers at ± 20% of the accident design flow rate and ambient conditions shall show ≥ 99% ~~halogenated hydrocarbon~~ removal. — LA.2 — M.4

5.5.10.a ~~(3)~~ A ~~locally generated DOP*~~ test of the HEPA filters at ± 20% of the accident design flow rate and ambient conditions shall show ≥ 99% ~~DOP~~ removal. — LA.2 — M.4

~~*Dioctylphthalate Particles~~

Add - SR 3.0.2 is applicable to VFTP — A.10

5. Control Room Air Filtration System

SEE ITS 5.5.10

a. Visual inspection of the filter installations shall be performed in accordance with ANSI N 510 (1975) every six months for the first two years and at least once per 24 months thereafter, or at any time fire, chemical releases or work done on the filters could alter their integrity.

SR 3.7.11.1

b. ~~The~~ Each charcoal filtration system shall be operated for a minimum of 15 minutes every month. A.4

SEE ITS 5.5.10

c. At least once per 24 months, the following conditions shall be demonstrated before the system can be considered operable:

(1) The pressure drop across the combined HEPA filters and charcoal adsorber banks is less than 6 inches of water at ambient conditions and accident design flow rates.

(2) Using either direct or indirect measurements, the flow rate of the system fans shall be shown to be at least 90% of accident design flow rate.

d. At least once per 24 months or at any time fire, chemical releases or work done on the filters could alter their integrity or after every 720 hours of charcoal adsorber use since the last test, the following conditions shall be demonstrated before the system can be considered operable:

(1) The charcoal shall have a methyl iodine removal efficiency $\geq$ 90% at $\pm$ 20% of the accident design flow rate, 0.05 to 0.15 mg/m^3 inlet methyl iodine concentration, $\geq$ 95% relative humidity and $\geq$ 125°F.

(2) A halogenated hydrocarbon (freon) test on charcoal adsorbers at $\pm$ 20% of the accident design flow rate and ambient conditions shall show $\geq$ 99% halogenated hydrocarbon removal.

(3) A locally generated DOP test of the HEPA filters at $\pm$ 20% of the accident design flow rate and ambient conditions shall show $\geq$ 99% DOP removal.

Add SR 3.7.11.2 A.5

Add SR 3.7.11.3 A.6

Add SR 3.7.11.4 M.3

Ventilation — A

5.5.10 ~~5.~~ Control Room Air Filtration System — Section C.5.a of RG 1.52, R2

5.5.10.a 5.5.10.b ~~a.~~ Visual inspection of the filter installations shall be performed in accordance with ANSI N 510 (1975) every six months for the first two years and at least once per 24 months thereafter, or at any time fire, chemical releases or work done on the filters could alter their integrity. — M.1, A.3

SEE ITS 3.7.11

b. The charcoal filtration system shall be operated for a minimum of 15 minutes every month.

5.5.10.d

c. At least once per 24 months, the following conditions shall be demonstrated before the system can be considered operable:

(1) The pressure drop across the combined prefilters (if installed), HEPA filters and charcoal adsorber banks is less than 6 inches of water at ambient conditions and accident design flow rates. — A.7

(2) ~~Using either direct or indirect measurements,~~ the flow rate of the system fans shall be shown to be at least 90% of accident design flow rate.

~~d.~~ At least once per 24 months or at any time fire, significant painting, chemical releases or work done on the filters could alter their integrity or after every 720 hours of charcoal adsorber use since the last test, the following conditions shall be demonstrated while system is in operation before the system can be considered operable: — M.2, M.3, A.6

<5.5.10.c> ~~(1)~~ The charcoal shall have a methyl iodine removal efficiency ≥ 90% at ± 20% of the accident design flow rate, 0.05 to 0.15 mg/m^3 inlet methyl iodine concentration, ≥ 95% relative humidity and ≥ 125°F. — LA.1

5.5.10.b ~~(2)~~ A halogenated hydrocarbon (freon) test on charcoal adsorbers at ± 20% of the accident design flow rate and ambient conditions shall show ≥ 99% halogenated hydrocarbon removal. — M.4, LA.2

5.5.10.a ~~(3)~~ A locally generated DOP test of the HEPA filters at ± 20% of the accident design flow rate and ambient conditions shall show ≥ 99% DOP removal. — M.4

SEE RELOCATED CTS

e. Each toxic gas monitoring system shall be demonstrated operable by performance of a channel check at least once per day, a channel test at least once per 31 days and a channel calibration at least once per 18 months.

CTS 4.5.A.6.

Fuel Storage Building Emergency Ventilation System

SR 3.7.13.2

~~a.~~ The fuel storage building emergency ventilation system fan shall be operated for a minimum of 15 minutes every month ~~when there is irradiated fuel in the spent fuel pit.~~ L.1

SEE ITS 5.5.10

b. Prior to handling of irradiated fuel, the following conditions shall be demonstrated before the system can be considered operable:

(1) The pressure drop across the combined HEPA filters and charcoal adsorber banks is less than 6 inches of water at ambient conditions and accident design flow rates.

(2) Using either direct or indirect measurements, the flow rate of the system fans shall be shown to be at least 90% of the accident design flow rate.

A.4

SR 3.7.13.1

(3) The filtration system bypass assembly shall be isolated ~~and leak tested to assure that it is properly sealed.~~ LA.1

verify every 30 days M.2

SEE ITS 5.5.10

c. Prior to handling of irradiated fuel, or at any time fire, chemical releases or work done on the filters could alter their integrity or after every 720 hours of charcoal adsorber use since the last test, the following conditions shall be demonstrated before the system can be considered operable:

(1) Charcoal shall have a methyl iodine removal efficiency $\geq$ 90% at $\pm$ 20% of the accident design flow rate, 0.05 to 0.15 mg/m^3 inlet methyl iodine concentration, $\geq$ 95% relative humidity and $\geq$ 125°F.

(2) A halogenated hydrocarbon (freon) test on charcoal adsorbers at $\pm$ 20% of the accident design flow rate and ambient conditions shall show $\geq$ 99% halogenated hydrocarbon removal.

A.4

Add SR 3.7.13.3

Add SR 3.7.13.5

A

Amendment No. ~~79~~, ~~108~~, ~~123~~, 125

SEE RELOCATED

e. Each toxic gas monitoring system shall be demonstrated operable by performance of a channel check at least once per day, a channel test at least once per 31 days and a channel calibration at least once per 18 months.

SEE ITS 3.7.13

6. Fuel Storage Building Emergency Ventilation System

a. The fuel storage building emergency ventilation system fan shall be operated for a minimum of 15 minutes every month when there is irradiated fuel in the spent fuel pit.

5.5.10.d

b. Prior to ~~handling of irradiated fuel~~ 24 months, the following conditions shall be demonstrated before the system can be considered operable: A9

(1) The pressure drop across the combined prefilters (if installed) HEPA filters and charcoal adsorber banks is less than 6 inches of water at ambient conditions and accident design flow rates. A.5

(2) ~~Using either direct or indirect measurements~~, the flow rate of the system fans shall be shown to be at least 90% of the accident design flow rate. A7

SEE ITS 3.7.13

(3) The filtration system bypass assembly shall be isolated and leak tested to assure that it is properly sealed.

c. Prior to ~~handling of irradiated fuel~~ 24 months or at any ~~time~~ significant painting, fire, chemical releases or work done on the filters could alter their integrity or after every 720 hours of charcoal adsorber use since the last test, the following conditions shall be demonstrated before the system can be considered operable: when in operation A9 M.3 A.(M.2

5.5.10.c

(1) Charcoal shall have a methyl iodine removal efficiency ≥ 90% at ± 20% of the accident design flow rate, 0.05 to 0.15 mg/m^3 inlet methyl iodine concentration, ≥ 95% relative humidity and ≥ 125°F.

5.5.10.b

~~(2)~~ A ~~halogenated hydrocarbon (freon)~~ test on charcoal adsorbers at ± 20% of the accident design flow rate and ambient conditions shall show ≥ 99% ~~halogenated hydrocarbon~~ removal. LA.2

R.18

e. ~~Each toxic gas monitoring system shall be demonstrated operable by performance of a channel check at least once per day, a channel test at least once per 31 days and a channel calibration at least once per 18 months.~~

SEE ITS 3.7.13 ITS 5.5.10

6. Fuel Storage Building Emergency Ventilation System

a. The fuel storage building emergency ventilation system fan shall be operated for a minimum of 15 minutes every month when there is irradiated fuel in the spent fuel pit.

b. Prior to handling of irradiated fuel, the following conditions shall be demonstrated before the system can be considered operable:

(1) The pressure drop across the combined HEPA filters and charcoal adsorber banks is less than 6 inches of water at ambient conditions and accident design flow rates.

(2) Using either direct or indirect measurements, the flow rate of the system fans shall be shown to be at least 90% of the accident design flow rate.

(3) The filtration system bypass assembly shall be isolated and leak tested to assure that it is properly sealed.

c. Prior to handling of irradiated fuel, or at any time fire, chemical releases or work done on the filters could alter their integrity or after every 720 hours of charcoal adsorber use since the last test, the following conditions shall be demonstrated before the system can be considered operable:

(1) Charcoal shall have a methyl iodine removal efficiency $\geq$ 90% at $\pm$ 20% of the accident design flow rate, 0.05 to 0.15 mg/m^3 inlet methyl iodine concentration, $\geq$ 95% relative humidity and $\geq$ 125°F.

(2) A halogenated hydrocarbon (freon) test on charcoal adsorbers at $\pm$ 20% of the accident design flow rate and ambient conditions shall show $\geq$ 99% halogenated hydrocarbon removal.

SEE ITS 5.5.10

(3) A locally generated DOP test of the HEPA filters at ± 20% of the accident design flow rate and ambient conditions shall show ≥ 99% DOP removal.

(4) Visual inspection in accordance with the applicable sections of ANSI N 510 (1975) of filter installations.

7. Electric Hydrogen Recombiner Systems

a. Each hydrogen recombiner system shall be demonstrated OPERABLE:

SR 3.6.8.1

~~1)~~ At least once every 6 months by verifying, during a Hydrogen 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~~ LA.1

~~2)~~ At least once per 24 months by:

~~a) Performing CHANNEL CALIBRATION of all recombiner instrumentation and control circuits,~~ LA.2

SR 3.6.8.2

~~b)~~ Verifying through a visual examination that there is no evidence of abnormal conditions within the recombiner enclosure ~~(i.e., loose wiring or structural connections, deposits of foreign materials, etc.), and~~ LA.1

SR 3.6.8.3

c) 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.~~ LA.1

Amendment No. ~~79~~, ~~125~~, 130

5.5.10.a ~~(3)~~ A locally generated DOP test of the HEPA filters at ± 20% of the accident design flow rate and ambient conditions shall show ≥ 99% DOP removal LA.Z M.4

5.5.10.a 5.5.10.b ~~(4)~~ Visual inspection in accordance with the applicable sections of ANSI N 510 (1975) of filter installations. Section C.5.a of RG 1.52, R2 M.1

SEE ITS 3.6.8

Electric Hydrogen Recombiner Systems

a. Each hydrogen recombiner system shall be demonstrated OPERABLE:

1) At least once every 6 months by verifying, during a Hydrogen 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

2) At least once per 24 months by:

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

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

c) 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.

B. Component Tests

1. Pumps

SEE ITS 3.5.2 3.5.3 3.6.6 3.7.8

a. The safety injection pumps, residual heat removal pumps, containment spray pumps and the auxiliary component cooling water pumps shall be started at quarterly intervals. The recirculation pumps shall be started at least once per 24 months.

b. Acceptable levels of performance shall be that the pumps start, reach their required developed head on recirculation flow, and operate for at least fifteen minutes.

2. Valves

SEE ITS 3.6.7

a. Each spray additive valve shall be cycled by operator action with the pumps shut down at least once per 24 months.

SEE ITS 3.5.1

b. The accumulator check valves shall be checked for operability at least once per 24 months.

LCO 3.4.14 SR 3.4.14.1

c. The following check valves PIVs shall be checked for gross leakage at least once per 24 months: A.7

857A & G	857J	857S & T	897B
857B	857K	857U & W	897C
857C	857L	895A	897D
857D	857M	895B	838A
857E	857N	895C	838B
857F	857P	895D	838C
857H	857Q & R	897A	838D

M.5

LA.1

Add Notes 1, 2 and 3 to SR 3.4.14.1 L.1

Add Acceptance Criteria to SR 3.4.14.1 M.4

Add LCO 3.4.14, Applicability A.3

Add Condition A and B and associated Req. Acts. M.1

Amendment No. ~~125~~, ~~129~~, ~~148~~, 178

Add Actions Notes 1 and 2 A.4

B. Component Tests

SEE ITS 3.5.2 and ITS 3.6.6

1. Pumps

a. The safety injection pumps, residual heat removal pumps, containment spray pumps and the auxiliary component cooling water pumps shall be started at quarterly intervals. The recirculation pumps shall be started at least once per 24 months.

b. Acceptable levels of performance shall be that the pumps start, reach their required developed head on recirculation flow, and operate for at least fifteen minutes.

2. Valves

SEE ITS 3.6.7

a. Each spray additive valve shall be cycled by operator action with the pumps shut down at least once per 24 months.

LCO 3.5.1

b. ~~The accumulator check valves shall be checked for operability at least once per 24 months.~~ LA.2

SEE ITS 3.4.14

c. The following check valves shall be checked for gross leakage at least once per 24 months:

857A & G	857J	857S & T	897B
857B	857K	857U & W	897C
857C	857L	895A	897D
857D	857M	895B	838A
857E	857N	895C	838B
857F	857P	895D	838C
857H	857Q & R	897A	838D

Amendment No. ~~125~~, ~~129~~, ~~148~~, 178

SEE ITS 3.6.6

SEE ITS 3.7.8

LA2

In accordance with Inservice Test Program

B. Component Tests

1. Pumps

SR 3.5.2.3

a. The safety injection pumps, residual heat removal pumps, containment spray pumps and the auxiliary component cooling water pumps shall be started at quarterly intervals. The recirculation pumps shall be started ~~at least once per 24 months~~

b. Acceptable levels of performance shall be that the pumps start, reach their required developed head on recirculation flow, ~~and operate for at least fifteen minutes~~

2. Valves

SEE ITS 3.6.7

a. Each spray additive valve shall be cycled by operator action with the pumps shut down at least once per 24 months.

SEE ITS 3.5.1

b. The accumulator check valves shall be checked for operability at least once per 24 months.

SEE ITS 3.4.14

c. The following check valves shall be checked for gross leakage at least once per 24 months:

857A & G	857J	857S & T	897B
857B	857K	857U & W	897C
857C	857L	895A	897D
857D	857M	895B	838A
857E	857N	895C	838B
857F	857P	895D	838C
857H	857Q & R	897A	838D

B. Component Tests

Add SR 3.5.3.1 (SR 3.5.2.7) — M.1

1. Pumps

SR 3.5.3.1 (SEE ITS 3.5.2 for SR 3.5.2.3)

a. The safety injection pumps, residual heat removal pumps, containment spray pumps and the auxiliary component cooling water pumps shall be started at intervals not greater than one month. The recirculation pumps shall be started at least once per 24 months.

b. Acceptable levels of performance shall be that the pumps start, reach their required developed head on recirculation flow, and operate for at least fifteen minutes.

2. Valves

SEE ITS 3.6.7

a. Each spray additive valve shall be cycled by operator action with the pumps shut down at least once per 24 months.

SEE ITS 3.5.1

b. The accumulator check valves shall be checked for operability at least once per 24 months.

SEE ITS 3.4.14

c. The following check valves shall be checked for gross leakage at least once per 24 months:

857A & G	857J	857S & T	897B
857B	857K	857U & W	897C
857C	857L	895A	897D
857D	857M	895B	838A
857E	857N	895C	838B
857F	857P	895D	838C
857H	857Q & R	897A	838D

SEE CTS MASTER MARKUP

B. Component Tests

1. Pumps

SR 3.6.6.4

~~a.~~ The ~~safety injection pumps, residual heat removal pumps~~ containment spray pumps and the auxiliary component cooling water pumps shall be started at quarterly intervals IAW IST Program LA.1 ~~The recirculation pumps shall be started at least once per 24 months.~~

b. Acceptable levels of performance shall be that the pumps start, reach their required developed head on recirculation flow, and operate for ~~at least fifteen minutes~~ A.7

2. Valves

SEE CTS MASTER MARKUP

a. Each spray additive valve shall be cycled by operator action with the pumps shut down at least once per 24 months.

b. The accumulator check valves shall be checked for operability at least once per 24 months.

c. The following check valves shall be checked for gross leakage at least once per 24 months:

857A & G	857J	857S & T	897B
857B	857K	857U & W	897C
857C	857L	895A	897D
857D	857M	895B	838A
857E	857N	895C	838B
857F	857P	895D	838C
857H	857Q & R	897A	838D

B. Component Tests

SEE ITS 3.5.2 3.5.3 3.6.6

1. Pumps

a. The safety injection pumps, residual heat removal pumps, containment spray pumps and the auxiliary component cooling water pumps shall be started at quarterly intervals. The recirculation pumps shall be started at least once per 24 months.

b. Acceptable levels of performance shall be that the pumps start, reach their required developed head on recirculation flow, and operate for at least fifteen minutes.

2. Valves

<3.6.7.4>

a. Each spray additive valve shall be cycled ~~by operator action with the pumps shut down~~ at least once per 24 months. A.6

SEE ITS 3.5.1

b. The accumulator check valves shall be checked for operability at least once per 24 months.

SEE ITS 3.4.14

c. The following check valves shall be checked for gross leakage at least once per 24 months:

857A & G	857J	857S & T	897B
857B	857K	857U & W	897C
857C	857L	895A	897D
857D	857M	895B	838A
857E	857N	895C	838B
857F	857P	895D	838C
857H	857Q & R	897A	838D

SR 3.4.14.1

~~d.~~ In addition to 4.5.B.2.c, the following check valves shall be checked for gross leakage every time the plant is shut down and the reactor coolant system has been depressurized to 700 psig or less. This gross leakage test shall also be performed following valve maintenance, repair or other work which could unseat these check valves: L.2 M.6 A.5

838A	895A	897A
838B	895B	897B
838C	895C	897C
838D	895D	897D

add second Freq for SR 3.4.14.1 L.2

Add third Freq for SR 3.4.14.1 M.6

LA.1

Basis

The Safety Injection System and the Containment Spray System are principal plant safeguards that are normally on standby during reactor operation. Complete systems tests cannot be performed when the reactor is operating because a safety injection signal causes reactor trip, main feedwater isolation and containment isolation, and a Containment Spray System test requires the system to be temporarily disabled. The method of assuring operability of these systems is, therefore, to combine systems tests to be performed during plant shutdowns, with more frequent component tests, which can be performed during reactor operation.

The systems tests demonstrate proper automatic operation of the Safety Injection and Containment Spray Systems. With the pumps blocked from starting, a test signal is applied to initiate automatic action and verification made that the components receive the safety injection signal in the proper sequence. The test demonstrates the operation of the valves, pump circuit breakers, and automatic circuitry.[4]

During reactor operation, the instrumentation which is depended on to initiate safety injection and containment spray is generally checked daily and the initiating circuits are tested monthly (in accordance with Specification 4.1). The testing of the analog channel inputs is accomplished in the same manner as for the reactor protection system. The engineered safety features logic system is tested by means of test switches to simulate inputs from the analog channels. The test switches allow actuation of the master relay, while at the same time blocking the slave relays. Verification that the logic is accomplished is indicated by the matrix test light. The slave relay coil circuits are continuously verified by a built-in monitoring circuit. In addition, the active components (pumps and valves) are to be tested in accordance with the Indian Point 3 Inservice Testing Program. The pumps, specified in the Technical Specifications, are tested on a quarterly basis to check the operation of the starting circuits and to verify that the pumps are in satisfactory running order. The exception to this quarterly test are the recirculation pumps which are tested during a refueling outage. The quarterly test interval is based on the judgement that more frequent testing would not significantly increase the reliability (i.e., the probability that the component would operate when required), yet more frequent testing would result in increased wear over a long period of time.

A.1

SEE ITS 3.4.14

d. In addition to 4.5.B.2.c, the following check valves shall be checked for gross leakage every time the plant is shut down and the reactor coolant system has been depressurized to 700 psig or less. This gross leakage test shall also be performed following valve maintenance, repair or other work which could unseat these check valves:

838A	895A	897A
838B	895B	897B
838C	895C	897C
838D	895D	897D

Basis

A.1

~~The Safety Injection System and the Containment Spray System are principal plant safeguards that are normally on standby during reactor operation. Complete systems tests cannot be performed when the reactor is operating because a safety injection signal causes reactor trip, main feedwater isolation and containment isolation, and a Containment Spray System test requires the system to be temporarily disabled. The method of assuring operability of these systems is, therefore, to combine systems tests to be performed during plant shutdowns, with more frequent component tests, which can be performed during reactor operation.~~

~~The systems tests demonstrate proper automatic operation of the Safety Injection and Containment Spray Systems. With the pumps blocked from starting, a test signal is applied to initiate automatic action and verification made that the components receive the safety injection signal in the proper sequence. The test demonstrates the operation of the valves, pump circuit breakers, and automatic circuitry.[1]~~

~~During reactor operation, the instrumentation which is depended on to initiate safety injection and containment spray is generally checked daily and the initiating circuits are tested monthly (in accordance with Specification 4.1). The testing of the analog channel inputs is accomplished in the same manner as for the reactor protection system. The engineered safety features logic system is tested by means of test switches to simulate inputs from the analog channels. The test switches allow actuation of the master relay, while at the same time blocking the slave relays. Verification that the logic is accomplished is indicated by the matrix test light. The slave relay coil circuits are continuously verified by a built-in monitoring circuit. In addition, the active components (pumps and valves) are to be tested in accordance with the Indian Point 3 Inservice Testing Program. The pumps, specified in the Technical Specifications, are tested on a quarterly basis to check the operation of the starting circuits and to verify that the pumps are in satisfactory running order. The exception to this quarterly test are the recirculation pumps which are tested during a refueling outage. The quarterly test interval is based on the judgement that more frequent testing would not significantly increase the reliability (i.e., the probability that the component would operate when required), yet more frequent testing would result in increased wear over a long period of time.~~

d. In addition to 4.5.B.2.c, the following check valves shall be checked for gross leakage every time the plant is shut down and the reactor coolant system has been depressurized to 700 psig or less. This gross leakage test shall also be performed following valve maintenance, repair or other work which could unseat these check valves:

SEE ITS 3.4.14

838A	895A	897A
838B	895B	897B
838C	895C	897C
838D	895D	897D

Basis

A.1

~~The Safety Injection System and the Containment Spray System are principal plant safeguards that are normally on standby during reactor operation. Complete systems tests cannot be performed when the reactor is operating because a safety injection signal causes reactor trip, main feedwater isolation and containment isolation, and a Containment Spray System test requires the system to be temporarily disabled. The method of assuring operability of these systems is, therefore, to combine systems tests to be performed during plant shutdowns, with more frequent component tests, which can be performed during reactor operation.~~

~~The systems tests demonstrate proper automatic operation of the Safety Injection and Containment Spray Systems. With the pumps blocked from starting, a test signal is applied to initiate automatic action and verification made that the components receive the safety injection signal in the proper sequence. The test demonstrates the operation of the valves, pump circuit breakers, and automatic circuitry.[1]~~

~~During reactor operation, the instrumentation which is depended on to initiate safety injection and containment spray is generally checked daily and the initiating circuits are tested monthly (in accordance with Specification 4.1). The testing of the analog channel inputs is accomplished in the same manner as for the reactor protection system. The engineered safety features logic system is tested by means of test switches to simulate inputs from the analog channels. The test switches allow actuation of the master relay, while at the same time blocking the slave relays. Verification that the logic is accomplished is indicated by the matrix test light. The slave relay coil circuits are continuously verified by a built-in monitoring circuit. In addition, the active components (pumps and valves) are to be tested in accordance with the Indian Point 3 Inservice Testing Program. The pumps, specified in the Technical Specifications, are tested on a quarterly basis to check the operation of the starting circuits and to verify that the pumps are in satisfactory running order. The exception to this quarterly test are the recirculation pumps which are tested during a refueling outage. The quarterly test interval is based on the judgement that more frequent testing would not significantly increase the reliability (i.e., the probability that the component would operate when required), yet more frequent testing would result in increased wear over a long period of time.~~

Other systems that are also important to the emergency cooling function are the accumulators, the Component Cooling System, the Service Water System, and the containment fan coolers. The accumulators are a passive safeguard. In accordance with Specification A.1, the water volume and pressure in the accumulators are checked periodically. The other systems mentioned operate when the reactor is in operation, and by these means are continuously monitored for satisfactory performance.

The charcoal portion of the containment air recirculation system is a passive safeguard which is isolated from the cooling air flow during normal reactor operation. Hence, the charcoal should have a long useful lifetime. The filter frames that house the charcoal are stainless steel and should also last indefinitely. However, the visual inspection specified in Section A.4(a) of this specification will be performed to verify that this is, in fact, the case. The iodine removal efficiency cannot be measured with the filter cells in place. Therefore, at periodic intervals a representative sample of charcoal is to be removed and tested to verify that the efficiencies for removal of methyl iodide are obtained.[2] The fuel storage building air treatment system is designed to filter the discharge of the fuel storage building atmosphere to the facility vent during normal conditions. As required by Specifications 3.8.A.12 and 3.8.C.6, the fuel storage building emergency ventilation system must be operable whenever irradiated fuel is being moved. However, if the irradiated fuel has had a continuous 45-day decay period, the fuel storage building emergency ventilation system is not technically necessary, even though the system is required to be operable during all fuel handling operations. The emergency ventilation fan is automatically started upon high radiation signal and since the bypass assembly is sealed by manually operated isolation devices, air flow is directed through the emergency ventilation HEPA filters and charcoal adsorbers.

High efficiency particulate absolute (HEPA) filters are installed before the charcoal adsorbers to prevent clogging of these adsorbers for all emergency air treatment systems. The charcoal adsorbers are installed to reduce the potential release of radio-iodine to the environment. The in-place test results should indicate a system leak tightness of less than or equal to one percent leakage for the charcoal adsorbers and a HEPA efficiency of greater than or equal to 99 percent removal of DOP particulates. The laboratory carbon sample test results should indicate a methyl iodide removal efficiency of greater than or equal to 90 percent on the fuel handling system samples, and greater than or equal to 85 percent on the containment system samples for expected accident conditions. With the efficiencies of the HEPA filters and charcoal adsorbers as specified, further assurance is provided that the resulting doses will be less than the 10 CFR 100 guidelines for the accidents analyzed.

The basis for the toxic gas monitoring system is given in Technical Specification Section 3.3.

The control room air treatment system is designed to filter the control room atmosphere for intake air and/or for recirculation during control room isolation conditions. The control room air treatment system is designed to automatically start upon control room isolation.

A.1

Other systems that are also important to the emergency cooling function are the accumulators, the Component Cooling System, the Service Water System, and the containment fan coolers. The accumulators are a passive safeguard. In accordance with Specification 4.1, the water volume and pressure in the accumulators are checked periodically. The other systems mentioned operate when the reactor is in operation, and by these means are continuously monitored for satisfactory performance.

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High efficiency particulate absolute (HEPA) filters are installed before the charcoal adsorbers to prevent clogging of these adsorbers for all emergency air treatment systems. The charcoal adsorbers are installed to reduce the potential release of radio-iodine to the environment. The in-place test results should indicate a system leak tightness of less than or equal to one percent leakage for the charcoal adsorbers and a HEPA efficiency of greater than or equal to 99 percent removal of DOP particulates. The laboratory carbon sample test results should indicate a methyl iodide removal efficiency of greater than or equal to 90 percent on the fuel handling system samples, and greater than or equal to 85 percent on the containment system samples for expected accident conditions. With the efficiencies of the HEPA filters and charcoal adsorbers as specified, further assurance is provided that the resulting doses will be less than the 10 CFR 100 guidelines for the accidents analyzed.

The basis for the toxic gas monitoring system is given in Technical Specification Section 3.3.

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Other systems that are also important to the emergency cooling function are the accumulators, the Component Cooling System, the Service Water System, and the containment fan coolers. The accumulators are a passive safeguard. In accordance with Specification 4.1, the water volume and pressure in the accumulators are checked periodically. The other systems mentioned operate when the reactor is in operation, and by these means are continuously monitored for satisfactory performance.

The charcoal portion of the containment air recirculation system is a passive safeguard which is isolated from the cooling air flow during normal reactor operation. Hence, the charcoal should have a long useful lifetime. The filter frames that house the charcoal are stainless steel and should also last indefinitely. However, the visual inspection specified in Section A.4(a) of this specification will be performed to verify that this is, in fact, the case. The iodine removal efficiency cannot be measured with the filter cells in place. Therefore, at periodic intervals a representative sample of charcoal is to be removed and tested to verify that the efficiencies for removal of methyl iodide are obtained.[2] The fuel storage building air treatment system is designed to filter the discharge of the fuel storage building atmosphere to the facility vent during normal conditions. As required by Specifications 3.8.A.12 and 3.8.C.6, the fuel storage building emergency ventilation system must be operable whenever irradiated fuel is being moved. However, if the irradiated fuel has had a continuous 45-day decay period, the fuel storage building emergency ventilation system is not technically necessary, even though the system is required to be operable during all fuel handling operations. The emergency ventilation fan is automatically started upon high radiation signal and since the bypass assembly is sealed by manually operated isolation devices, air flow is directed through the emergency ventilation HEPA filters and charcoal adsorbers.

High efficiency particulate absolute (HEPA) filters are installed before the charcoal adsorbers to prevent clogging of these adsorbers for all emergency air treatment systems. The charcoal adsorbers are installed to reduce the potential release of radio-iodine to the environment. The in-place test results should indicate a system leak tightness of less than or equal to one percent leakage for the charcoal adsorbers and a HEPA efficiency of greater than or equal to 99 percent removal of DOP particulates. The laboratory carbon sample test results should indicate a methyl iodide removal efficiency of greater than or equal to 90 percent on the fuel handling system samples, and greater than or equal to 85 percent on the containment system samples for expected accident conditions. With the efficiencies of the HEPA filters and charcoal adsorbers as specified, further assurance is provided that the resulting doses will be less than the 10 CFR 100 guidelines for the accidents analyzed.

The basis for the toxic gas monitoring system is given in Technical Specification Section 3.3.

The control room air treatment system is designed to filter the control room atmosphere for intake air and/or for recirculation during control room isolation conditions. The control room air treatment system is designed to automatically start upon control room isolation.

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~~The charcoal portion of the containment air recirculation system is a passive safeguard which is isolated from the cooling air flow during normal reactor operation. Hence, the charcoal should have a long useful lifetime. The filter frames that house the charcoal are stainless steel and should also last indefinitely. However, the visual inspection specified in Section A.4(a) of this specification will be performed to verify that this is, in fact, the case. The iodine removal efficiency cannot be measured with the filter cells in place. Therefore, at periodic intervals a representative sample of charcoal is to be removed and tested to verify that the efficiencies for removal of methyl iodide are obtained.(2) The fuel storage building air treatment system is designed to filter the discharge of the fuel storage building atmosphere to the facility vent during normal conditions. As required by Specifications 3.8.A.12 and 3.8.C.6, the fuel storage building emergency ventilation system must be operable whenever irradiated fuel is being moved. However, if the irradiated fuel has had a continuous 45-day decay period, the fuel storage building emergency ventilation system is not technically necessary, even though the system is required to be operable during all fuel handling operations. The emergency ventilation fan is automatically started upon a high radiation signal, and since the bypass assembly is sealed by manually operated isolation devices, air flow is directed through the emergency ventilation HEPA filters and charcoal adsorbers.~~

~~High efficiency particulate absolute (HEPA) filters are installed before the charcoal adsorbers to prevent clogging of these adsorbers for all emergency air treatment systems. The charcoal adsorbers are installed to reduce the potential release of radio-iodine to the environment. The in-place test results should indicate a system leak tightness of less than or equal to one percent leakage for the charcoal adsorbers and a HEPA efficiency of greater than or equal to 99 percent removal of DOP particulates. The laboratory carbon sample test results should indicate a methyl iodide removal efficiency of greater than or equal to 90 percent on the fuel handling system samples, and greater than or equal to 85 percent on the containment system samples for expected accident conditions. With the efficiencies of the HEPA filters and charcoal adsorbers as specified, further assurance is provided that the resulting doses will be less than the 10 CFR 100 guidelines for the accidents analyzed.~~

~~The basis for the toxic gas monitoring system is given in Technical Specification Section 3.3.~~

~~The control room air treatment system is designed to filter the control room atmosphere for intake air and/or for recirculation during control room isolation conditions. The control room air treatment system is designed to automatically start upon control room isolation.~~

A.1

High efficiency particulate absolute (HEPA) filters are installed before the charcoal adsorbers to similarly prevent clogging of these adsorbers. The charcoal adsorbers are installed to reduce the potential intake of radio-iodine by control room personnel. The in-place test results should indicate a system leak tightness of less than or equal to one percent leakage for the charcoal adsorbers and a HEPA filter efficiency of greater than or equal to 99 percent removal of DOP particulates. The laboratory carbon sample test results should indicate a methyl iodide removal efficiency of greater than or equal to 90 percent for expected accident conditions.

With the efficiencies of the HEPA filters and charcoal adsorbers as specified, further assurance is provided that the resulting doses will be less than the allowable levels stated in Criterion 19 of the General Design Criteria for Nuclear Power Plants, Appendix A to 10CFR Part 50.

A pressure drop across the combined HEPA filters and charcoal adsorbers of less than or equal to 6.0 inches of water at the system design flow rate will indicate that the filters and adsorbers are not clogged by excessive amounts of foreign matter. Pressure drop should be determined at least once per operating cycle to show system performance capability. Proper operation of the system fans should also be verified at least every refueling by either direct or indirect measurements.

If results of charcoal tests are unsatisfactory, two additional samples may be tested. If both of these tests are acceptable, the charcoal may be considered satisfactory for use in the plant. Should the charcoal of any of these air filtration systems fail to satisfy the test criteria outlined in this specification, the charcoal beds will be replaced with new charcoal which satisfies the requirements for new charcoal outlined in Regulatory Guide 1.52 (Revision June, 1973).

The hydrogen recombiner system is an engineered safety feature which would be used only following a loss-of-coolant accident to control the hydrogen evolved in the containment. The system is not expected to be needed until approximately 10 days have elapsed following the accident. At this time, the hydrogen concentration in the containment will have reached 3.0% by volume, which is the design concentration for starting the recombiner system.(3) Actual starting of the system will be based upon containment atmosphere sample analysis. The required surveillance testing of each unit will demonstrate the operability of the system. The bi-annual testing of the containment hydrogen monitoring system will demonstrate the availability of this system.

A.1

~~For the eight flow distribution valves (856 A, C, D, E, F, H, J and K), verification of the valve mechanical stop adjustments is performed periodically to provide assurance that the high head safety injection flow distribution is in accordance with flow values assumed in the core cooling analysis.~~

~~Gross leakage testing of the reactor coolant system pressure isolation valves and the Low Pressure Injection(LPI)/residual heat removal(RHR) system valves reduces the probability of an inter-system LOCA[4]. These tests implement the requirements set forth in NRC generic letter dated February 23, 1980, regarding testing of LPI/RHR system check valves. This amendment provides a basis for the rescission of item A.5. of a Confirmatory Order issued by the Commission to Indian Point 3 in a letter dated, February 11, 1980. To satisfy ALARA requirements, gross leakage (>10 gpm) may be measured indirectly (i.e. using installed pressure and flow indications).~~

A.1

~~References~~

~~(1) FSAR Section 6.2~~

~~(2) FSAR Section 6.4~~

~~(3) FSAR Section 6.8~~

~~(4) WASH 1400~~

A.1

For the eight flow distribution valves (856 A, C, D, E, F, H, J and K), verification of the valve mechanical stop adjustments is performed periodically to provide assurance that the high head safety injection flow distribution is in accordance with flow values assumed in the core cooling analysis.

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References

(1) FSAR Section 6.2

(2) FSAR Section 6.4

(3) FSAR Section 6.8

(4) WASH 1400

A.1

For the eight flow distribution valves (856 A, C, D, E, F, H, J and K), verification of the valve mechanical stop adjustments is performed periodically to provide assurance that the high head safety injection flow distribution is in accordance with flow values assumed in the core cooling analysis.

Gross leakage testing of the reactor coolant system pressure isolation valves and the Low Pressure Injection(LPI)/residual heat removal(RHR)system valves reduces the probability of an inter-system LOCA[4]. These tests implement the requirements set forth in NRC generic letter dated February 23, 1980, regarding testing of LPI/RHR system check valves. This amendment provides a basis for the rescission of item A.5. of a Confirmatory Order issued by the Commission to Indian Point 3 in a letter dated February 11, 1980. To satisfy ALARA requirements, gross leakage (>10 gpm) may be measured indirectly (i.e. using installed pressure and flow indications).

<u>References</u>

(1) FSAR Section 6.2

(2) FSAR Section 6.4

(3) FSAR Section 6.8

(4) WASH 1400

4.6 EMERGENCY POWER SYSTEM PERIODIC TESTS

A.2

~~Applicability~~

~~Applies to periodic testing and surveillance requirements of the emergency power system.~~

~~Objective~~

~~To verify that the emergency power system will respond promptly and properly when required.~~

~~Specification~~

Add 4 notes to SR 3.8.1.3 — A.6

The following tests and ~~surveillance shall be performed as stated:~~ — A.1

Add note to SR 3.8.1.2 — A.7

A. Diesel Generators

Add SR 3.8.1.2 Acceptance criteria — M.3

SR 3.8.1.2 ~~1.~~ Each month each diesel generator shall be manually started and
SR 3.8.1.3 synchronized to its bus or buses and shall ~~be allowed to assume the normal bus load and run for a period of time sufficient to reach stable operating temperatures.~~

Add SR 3.8.1.3 Acceptance Criteria — M.

SR 3.8.1.10 ~~2.~~ At least once per 24 months each diesel generator shall be manually started, synchronized and loaded up to its ~~2 hour rating and run for a period of at least 105 minutes.~~ — M.8

SR 3.8.1.13 — L.7

SR 3.8.1.12 ~~3.~~ At least once per 24 months*, simulate a loss of all normal AC station service power supplies in conjuction with a simulated Safety Injection signal, and verify: — A.4

actual or

SR 3.8.1.12.a, b a. the required bus load shedding;

SR 3.8.1.12.c b. the automatic start of each diesel generator; and

c. the restoration to operation of particular vital equipment, via the diesel generator ~~assuming the required load within 60 seconds after the initial start signal.~~ — A.5

SR 3.8.1.11

Add SR 3.8.1.12 acceptance criteria — M.9

SR 3.8.1.11 * The time delay relays will be tested at intervals no greater than 22.5 months (18 months + 25%). — L.6

Add note to SR 3.8.1.11

Add SR 3.8.1.5 — M.4

Add SR 3.8.1.7 and 3.8.1.8 — M.6

Add SR 3.8.1.6 — M.5

Add SR 3.8.1.9 — M.7

4.6 EMERGENCY POWER SYSTEM PERIODIC TESTS

A.2

~~Applicability~~

~~Applies to periodic testing and surveillance requirements of the emergency power system.~~

~~Objective~~

~~To verify that the emergency power system will respond promptly and properly when required.~~

Specification

The following tests and surveillance shall be performed as stated:

SR 3.8.2.1

SEE ITS 3.8.1

~~A.~~ Diesel Generators

1. Each month each diesel generator shall be manually started and synchronized to its bus or buses and shall be allowed to assume the normal bus load and run for a period of time sufficient to reach stable operating temperatures.

2. At least once per 24 months each diesel generator shall be manually started, synchronized and loaded up to its 2 hour rating and run for a period of at least 105 minutes.

3. At least once per 24 months*, simulate a loss of all normal AC station service power supplies in conjuction with a simulated Safety Injection signal, and verify:

   a. the required bus load shedding;

   b. the automatic start of each diesel generator; and

   c. the restoration to operation of particular vital equipment, via the diesel generator assuming the required load within 60 seconds after the initial start signal.

* The time delay relays will be tested at intervals no greater than 22.5 months (18 months + 25%).

L.

M.

Amendment No. ~~123~~, ~~138~~, 142

A.1

4. ~~Each diesel generator shall be inspected and maintained following the manufacturer's recommendations for this class of stand-by service.~~ LA.4

~~The above tests will be considered satisfactory if the required minimum safeguards equipment operates as designed.~~ A.1

B. Station Batteries

1. Every month the voltage of each cell, the specific gravity and temperature of a pilot cell in each battery and each battery voltage shall be measured and recorded.

2. Every 3 months each battery shall be subjected to a 24 hour equalizing charge, and the specific gravity of each cell, the temperature reading of every fifth cell, the height of electrolyte, and the amount of water added shall be measured and recorded.

SEE ITS 3.8.4 & ITS 3.8.6

3. At least once per 24 months, during shutdown, each battery shall be subjected to a service test and a visual inspection of the plates.[1]

4. At least once per 60 months, during shutdown, each battery shall be subjected to a performance discharge (or modified performance discharge) test.[1,2] This test shall verify that the battery capacity is at least 80% of the manufacturer's rating.

5. Any battery which is demonstrated to have less than 90% of the manufacturer's rating or, whose capacity drops more than 10% of rated capacity from its previous performance discharge (or modified performance discharge) test, shall be subjected to a performance discharge (or modified performance discharge) test annually, during shutdown, until the battery is replaced.

~~**Basis**~~

~~The tests specified are designed to demonstrate that the diesel generators will provide power for operation of equipment. They also assure that the emergency generator system controls and the control systems for the safeguards equipment will function automatically in the event of a loss of all normal 480v AC station service power. During the simulated loss of power/safety injection system test of specification 4.6.A.3, certain safeguards valves will be closed and made inoperable, to prevent Safety Injection flow to the core.~~ A.1

1. A modified performance discharge test may be performed in lieu of the battery service test every other 24 month operating cycle.

2. The first time a performance discharge (or modified performance discharge test) will be performed will be in refueling outage 10/11.

Add SR 3.8.4.2

M.2

SEE ITS 3.8.1

4. Each diesel generator shall be inspected and maintained following the manufacturer's recommendations for this class of stand-by service.

The above tests will be considered satisfactory if the required minimum safeguards equipment operates as designed.

SEE ITS 3.8.6

~~B.~~ Station Batteries

SR 3.8.4.1

~~1.~~ Every month the voltage of each cell, the specific gravity and temperature of a pilot cell in each battery and each battery voltage shall be measured ~~and recorded~~. A.4 M.6

SEE ITS 3.8.6

2. Every 3 months each battery shall be subjected to a 24 hour equalizing charge, and the specific gravity of each cell, the temperature reading of every fifth cell, the height of electrolyte, and the amount of water added shall be measured and recorded.

SR 3.8.4.3 ~~3.~~ At least once per 24 months, during shutdown, each battery shall be subjected to a service test ~~and a visual inspection of the plates~~.[1] LA.1

SR 3.8.4.4 Note to SR

~~4.~~ At least once per 60 months, during shutdown, each battery shall be subjected to a performance discharge (or modified performance discharge) test.[1,2] This test shall verify that the battery capacity is at least 80% of the manufacturer's rating.

SR 3.8.4.4 Frequency

~~5.~~ ~~Any battery which is demonstrated to have less than 90% of the manufacturer's rating or, whose capacity drops more than 10% of rated capacity from its previous performance discharge (or modified performance discharge) test, shall be subjected to a performance discharge (or modified performance discharge) test annually, during shutdown, until the battery is replaced.~~ M.5

~~Basis~~

~~The tests specified are designed to demonstrate that the diesel generators will provide power for operation of equipment. They also assure that the emergency generator system controls and the control systems for the safeguards equipment will function automatically in the event of a loss of all normal 480v AC station service power. During the simulated loss of power/safety injection system test of specification 4.6.A.3, certain safeguards valves will be closed and made inoperable, to prevent Safety Injection flow to the core.~~ A.1

1. A modified performance discharge test may be performed in lieu of the battery service test ~~every other 24 month operating cycle~~. A.5

2. ~~The first time a performance discharge (or modified performance discharge test) will be performed will be in refueling outage 10/11.~~ A.3

Add LCO 3.8.6 — M.1

Add LCO 3.8.6, Action Note — A.3

Add LCO 3.8.6, Applicability — A.2

Add Condition A and associated Req Actions — M.1

SEE ITS 3.8.1

4. Each diesel generator shall be inspected and maintained following the manufacturer's recommendations for this class of stand-by service.

The above tests will be considered satisfactory if the required minimum safeguards equipment operates as designed.

SEE ITS 3.8.4

B. Station Batteries — L.2

SR 3.8.6.1 T 3.8.6-1, Cat A SR 3.8.6.2

1. Every month the voltage of each cell, the specific gravity and temperature of a pilot cell in each battery and each battery voltage shall be measured ~~and recorded~~. — L.1 — LA.2 — A.4

SR 3.8.6.2 T 3.8.6-1, Cat B

2. Every 3 months ~~each battery shall be subjected to a 24 hour equalizing charge~~ and the specific gravity of each cell, the temperature reading of every fifth cell, the height of electrolyte, ~~and the amount of water added shall be measured and recorded~~. — LA.1 — L.2 — LA.2

SEE ITS 3.8.4

3. At least once per 24 months, during shutdown, each battery shall be subjected to a service test and a visual inspection of the plates.[1]

4. At least once per 60 months, during shutdown, each battery shall be subjected to a performance discharge (or modified performance discharge) test.[1,2] This test shall verify that the battery capacity is at least 80% of the manufacturer's rating.

5. Any battery which is demonstrated to have less than 90% of the manufacturer's rating or, whose capacity drops more than 10% of rated capacity from its previous performance discharge (or modified performance discharge) test, shall be subjected to a performance discharge (or modified performance discharge) test annually, during shutdown, until the battery is replaced.

~~**Basis**~~

~~The tests specified are designed to demonstrate that the diesel generators will provide power for operation of equipment. They also assure that the emergency generator system controls and the control systems for the safeguards equipment will function automatically in the event of a loss of all normal 480v AC station service power. During the simulated loss of power/safety injection system test of specification 4.6.A.3, certain safeguards valves will be closed and made inoperable, to prevent Safety Injection flow to the core.~~ — A.1

SEE ITS 3.8.4

1. A modified performance discharge test may be performed in lieu of the battery service test every other 24 month operating cycle.

2. The first time a performance discharge (or modified performance discharge test) will be performed will be in refueling outage 10/11.

Add Acceptance Criteria, Table 3.8.6-1 — A.4 — M.1

Add T 3.8.6-1, Note (b) — L.2

Add Table 3.8.6-1, Note (a) — A.4

A.1

The testing frequency specified will be often enough to identify and correct any mechanical or electrical deficiency before it can result in a system failure. The fuel supply is continuously monitored. An abnormal condition in these systems would be signaled without having to place the diesel generators themselves on test.

Each diesel generator has a continuous rating of 1750 kw and a 2 hour rating of 1950 kw. Two diesels can power the minimum safeguards loads. To ensure that each diesel can operate at its 2 hour rating (as required by specification 4.6.A.2.), each diesel will be loaded to 1900-1950 kw and run for at least 105 minutes.

Station batteries will deteriorate with time, but precipitous failure is extremely unlikely. The surveillance specified is that which has been demonstrated over the years to provide an indication of a cell becoming unserviceable long before it fails. The periodic equalizing charge will ensure that the ampere-hour capability of the batteries is maintained.

The service and performance discharge test of each battery, together with the visual inspection of the plates, will assure the continued integrity of the batteries. The batteries are of the type that can be visually inspected, and this method of assuring the continued integrity of the battery is proven standard power plant practice.

The battery service test demonstrates the capability of the battery to meet the system design requirements. The Indian Point Unit 3 design duty cycle loads are determined by a LOCA concurrent with a loss of AC power.

The performance discharge test is a test of the constant current capacity of a battery, normally done in the as found condition after having been in service, to detect any change in the capacity determined by the acceptance test. The test is intended to determine overall battery degradation due to age and usage.

The modified battery performance discharge test is a composite test which addresses both the service test and performance discharge test requirements. It shall consist of a one minute peak load equivalent to that of the service test and a constant discharge current for the remainder of the test which envelopes the next highest load value of the service test. The purpose of the modified performance discharge test is to compare the capacity of the battery against the manufacturer's specified capacity and thereby determine when the battery is approaching the end of its life, as well as to demonstrate capability to meet system design requirements. Every other 24 month operating cycle, the modified performance discharge test may be performed in lieu of the battery service test required by Technical Specification 4.6.B.3.

The station batteries are required for plant operation, and performing the station battery service and performance discharge (or modified performance discharge) test require the reactor to be shutdown.

<u>Reference</u>
FSAR, Section 8.2

A.1

The testing frequency specified will be often enough to identify and correct any mechanical or electrical deficiency before it can result in a system failure. The fuel supply is continuously monitored. An abnormal condition in these systems would be signaled without having to place the diesel generators themselves on test.

Each diesel generator has a continuous rating of 1750 kw and a 2 hour rating of 1950 kw. Two diesels can power the minimum safeguards loads. To ensure that each diesel can operate at its 2 hour rating (as required by specification 4.6.A.2), each diesel will be loaded to 1900-1950 kw and run for at least 105 minutes.

Station batteries will deteriorate with time, but precipitous failure is extremely unlikely. The surveillance specified is that which has been demonstrated over the years to provide an indication of a cell becoming unserviceable long before it fails. The periodic equalizing charge will ensure that the ampere-hour capability of the batteries is maintained.

The service and performance discharge test of each battery, together with the visual inspection of the plates, will assure the continued integrity of the batteries. The batteries are of the type that can be visually inspected, and this method of assuring the continued integrity of the battery is proven standard power plant practice.

The battery service test demonstrates the capability of the battery to meet the system design requirements. The Indian Point Unit 3 design duty cycle loads are determined by a LOCA concurrent with a loss of AC power.

The performance discharge test is a test of the constant current capacity of a battery, normally done in the as found condition after having been in service, to detect any change in the capacity determined by the acceptance test. The test is intended to determine overall battery degradation due to age and usage.

The modified battery performance discharge test is a composite test which addresses both the service test and performance discharge test requirements. It shall consist of a one minute peak load equivalent to that of the service test and a constant discharge current for the remainder of the test which envelopes the next highest load value of the service test. The purpose of the modified performance discharge test is to compare the capacity of the battery against the manufacturer's specified capacity and thereby determine when the battery is approaching the end of its life, as well as to demonstrate capability to meet system design requirements. Every other 24 month operating cycle, the modified performance discharge test may be performed in lieu of the battery service test required by Technical Specification 4.6.B.3.

The station batteries are required for plant operation, and performing the station battery service and performance discharge (or modified performance discharge) test require the reactor to be shutdown.

<u>Reference</u>
FSAR, Section 8.2

A.1

The testing frequency specified will be often enough to identify and correct any mechanical or electrical deficiency before it can result in a system failure. The fuel supply is continuously monitored. An abnormal condition in these systems would be signaled without having to place the diesel generators themselves on test.

Each diesel generator has a continuous rating of 1750 kw and a 2 hour rating of 1950 kw. Two diesels can power the minimum safeguards loads. To ensure that each diesel can operate at its 2 hour rating (as required by specification 4.6.A.2.), each diesel will be loaded to 1900-1950 kw and run for at least 105 minutes.

Station batteries will deteriorate with time, but precipitous failure is extremely unlikely. The surveillance specified is that which has been demonstrated over the years to provide an indication of a cell becoming unserviceable long before it fails. The periodic equalizing charge will ensure that the ampere-hour capability of the batteries is maintained.

The service and performance discharge test of each battery, together with the visual inspection of the plates, will assure the continued integrity of the batteries. The batteries are of the type that can be visually inspected, and this method of assuring the continued integrity of the battery is proven standard power plant practice.

The battery service test demonstrates the capability of the battery to meet the system design requirements. The Indian Point Unit 3 design duty cycle loads are determined by a LOCA concurrent with a loss of AC power.

The performance discharge test is a test of the constant current capacity of a battery, normally done in the as found condition after having been in service, to detect any change in the capacity determined by the acceptance test. The test is intended to determine overall battery degradation due to age and usage.

The modified battery performance discharge test is a composite test which addresses both the service test and performance discharge test requirements. It shall consist of a one minute peak load equivalent to that of the service test and a constant discharge current for the remainder of the test which envelopes the next highest load value of the service test. The purpose of the modified performance discharge test is to compare the capacity of the battery against the manufacturer's specified capacity and thereby determine when the battery is approaching the end of its life, as well as to demonstrate capability to meet system design requirements. Every other 24 month operating cycle, the modified performance discharge test may be performed in lieu of the battery service test required by Technical Specification 4.6.B.3.

The station batteries are required for plant operation, and performing the station battery service and performance discharge (or modified performance discharge) test require the reactor to be shutdown.

Reference
FSAR, Section 8.2

4.7 MAIN STEAM STOP VALVES

A.2

~~Applicability~~

~~Applies to periodic testing of the main steam stop valves.~~

~~Objective~~

~~To verify the ability of the main steam stop valves to close upon signal.~~

Specification T.3.3.2-1, #4a

A.19

SR 3.3.2.6 The main steam stop valves shall be tested at least once per 24 months. Closure time of five seconds or less shall be verified.

SEE ITS 3.7.2

~~Basis~~

~~The main steam stop valves serve to limit an excessive Reactor Coolant System cooldown rate and resultant reactivity insertion following a main steam break incident.[1] Their ability to close upon signal should be verified at least once per 24 months. A closure time of five seconds was selected as being consistent with expected response time for instrumentation as detailed in the steam line break incident analysis.[2]~~

References

(1) FSAR - Section 10.5

(2) FSAR - Section 14.2.5

Add SR 3.7.5.1 M.4

ITS 3.7.5
A.1

4.8 AUXILIARY FEEDWATER SYSTEM

~~Applicability~~

~~Applies to periodic testing requirements of the Auxiliary Feedwater System.~~ A.2

~~Objective~~

~~To verify the operability of the Auxiliary Feedwater System and its ability to respond properly when required.~~

~~Specification~~

IAW IST Program LA.2

SR 3.7.5.2 1. a. Each auxiliary feedwater pump will be started manually from the control room at ~~monthly intervals on a staggered test basis, (i.e., one pump per month, so that each pump is tested once during a 3 month period)~~ ~~with full flow established to the steam generators at least once per 24 months.~~ L.3

SR 3.7.5.3 b. The auxiliary feedwater pumps discharge valves will be tested by operator action at intervals not greater than six months.

SEE ITS 3.7.7 c. Backup supply valves from the city water system will be tested at least once per 24 months. ~~[See Note A, below]~~

SR 3.7.5.2 ~~2~~. Acceptance levels of performance shall be that the pumps start, reach their required developed head ~~and operate for at least fifteen minutes.~~ A.7

3. At least once per 24 months,

each automatic M.5

SR 3.7.5.3 a. Verify that the ~~recirculation~~ valve will actuate to its correct position.

SR 3.7.5.4 b. Verify that each auxiliary feedwater pump will start as designated automatically upon receipt of an auxiliary feedwater actuation ~~test~~ signal. actuation A.8

Add SR 3.7.5.4, Note 1 L.2

Add SR 3.7.5.4, Note 2 M.1

~~Basis~~

~~The testing of the auxiliary feedwater pumps will verify their operability. The capacity of any one of the three auxiliary feedwater pumps is sufficient to meet decay heat removal requirements.~~ A.1

~~Note A: Testing of the backup supply valves may be deferred until the next refueling outage (RO9), but no later than May 31, 1997.~~

Deleted by TSCR 98-043

Amendment No. ~~38~~, ~~125~~, ~~128~~, ~~172~~, 178

~~Verification of correct operation will be made both from instrumentation within the main control room and direct visual observation of the pumps.~~

~~Reference~~

~~FSAR - Sections 10.4, 14.1.9 and 14.2.5 and response to Question 7.23.~~

A.1

4.9 STEAM GENERATOR TUBE INSERVICE SURVEILLANCE

A.2

~~Applicability~~

~~Applies to inservice surveillance of the steam generator tubes.~~

~~Objective~~

~~To assure the continued integrity of the steam generator tubes that are a part of the primary coolant pressure boundary.~~

~~Specification~~

5.5.8 Steam generator tubes shall be determined operable by the following inspection program and corrective measures:

5.5.8.d ~~A.~~ ~~Inspection Requirements~~ Classification of Results

5.5.8.d.1 ~~1.~~ Definitions

~~a.~~ Imperfection is an exception to the dimension, finish, or contour required by drawing or specification.

~~b.~~ Degradation means a service-induced cracking, wastage, wear or corrosion.

~~c.~~ Degraded Tube is a tube that contains imperfections caused by degradation large enough to be reliably detected by eddy current inspection. This is considered to be 20% degradation.

~~d.~~ % Degradation is an estimate % of the tube wall thickness affected or removed by degradation.

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

~~f.~~ Tube Plugging Limit is the tube imperfection depth at or beyond which the tube must either be removed from service or repaired. This is considered to be an imperfection depth of 40%.

~~g.~~ Sleeve Plugging Limit - is the sleeve imperfection depth at or beyond which the sleeved tube must be removed from service or repaired. This is considered to be an imperfection depth of 40% for tube sleeves.

5.5.8.d.1 ~~h.~~ Tube Inspection is a full length 5.5-1 inspection for the initial 3% sample specified in Table 4.9-1. Supplemental sample inspections (after the intial 3% sample) may be limited to a partial length inspection concentrating on those locations where degradation has been found.

A.1

SG Selection and SG Tube Sample Size

5.5.8.a ~~2.~~ ~~Sample Size and the Number of Steam Generators to be Inspected~~

5.5.8.a.1 ~~a.~~ At the first inservice inspection subsequent to the pre-service inspection, six percent of the tubes in each of two steam generators shall be inspected as a minimum.

5.5.8.a.2 ~~b.~~ At the second inservice inspection subsequent to the pre-service inspection, twelve percent of the tubes in one of the two steam generators not inspected during the first inservice inspection shall be inspected as a minimum.

5.5.8.a.3 ~~c.~~ At the third inservice inspection subsequent to the pre-service inspection, twelve percent of the tubes in the steam generator not inspected during the first two inservice inspections shall be inspected as a minimum.

5.5.8.a.4 ~~d.~~ Fourth and subsequent inservice inspections may be limited to one steam generator on a rotating schedule encompassing ~~3N% of the tubes (where N is the number of steam generators in the plant)~~ 12% if the results of the first or previous inspections indicate that all steam generators are performing in a like manner. Under some circumstances, the operating conditions in one or more steam generators may be found to be more severe than those in other steam generators. Under such circumstances, the sample sequences should be modified to inspect the steam generator with the most severe conditions.

5.5.8.a.5 ~~e.~~ Unscheduled inspections should be conducted on the affected steam generator(s) in accordance with the first sample inspection specified in Table 4.9-1 5.5-1 in the event of primary-to-

5.5.8.a.5 secondary tube leaks (not including leaks originated from tube-to-tube sheet welds) exceeding technical specifications, a seismic occurrence greater than an operating basis earthquake, a loss-of-coolant accident requiring actuation of engineered safeguards, or a major steam line or feedwater line break.

~~3.~~ ~~Extent and Result of Steam Generator Tube Inspection~~ SG Tube Selection Criteria

5.5.8.a, 5.5.8.c.2, 5.5.8.e ~~a.~~ The minimum sample size, inspection result classification, and the corresponding action required are specified in Table ~~4.9-1~~ 5.5-1.

5.5.8.b.1 ~~b.~~ Tubes for the inspection should be selected on a random basis except where experience in similar plants with similar water chemistry indicates critical areas to be inspected.

5.5.8.b.2 ~~c.~~ The first sample inspection subsequent to the preservice inspection should include all nonplugged tubes that previously had detectable wall penetration (> 20%) and should also include tubes in those areas where experience has indicated potential problems.

5.5.8.b.3 ~~d.~~ The second and third sample inspections in Table ~~4.9-1~~ 5.5-1 may be limited to the partial tube inspection only, concentrating on tubes in the areas of the tube sheet array and on the portion of the tube where tubes with imperfections were found.

5.5.8.b.4 ~~e.~~ In all inspections, previously degraded tubes must exhibit significant (> 10%) further wall penetration to be included in the percentage calculation for the result categories in Table ~~4.9-1~~ 5.5-1.

5.5.8.c

~~4.~~ Interval of Inspection

~~a.~~ ~~The first inservice inspection of steam generators should be performed after six effective full power months but not later than completion of the first refueling outage.~~ A.4

5.5.8.c.1 ~~b.~~ ~~Subsequent~~ inservice inspections should be not less than 12 or more than 24 calendar months after the previous inspection.

5.5.8.c.2 ~~c.~~ If the results of two consecutive inspections, not including the preservice inspection, all fall into the C-1 category, the frequency of inspection may be extended to 40-month intervals.* Also, if it can be demonstrated through two consecutive inspections that previously observed degradation has not continued and no additional degradation has occurred, a 40-month inspection interval may be initiated.

Add SR 3.0.2 is applicable A.5

~~B.~~ Corrective Measures

5.5.8.e.2 All leaking tubes and defective tubes should be: (1) plugged, or (2) repaired.

~~F.~~ Reports

SEE ITS 5.6

1. Following each inservice inspection of steam generator tubes, the number of tubes plugged and repaired in each steam generator shall be reported to the Commission within 15 days.

2. The complete results of the steam generator tube inservice inspection shall be reported in writing on an annual basis for the period in which the inspection was completed per Specification 6.9.2. This report shall include:

   a. Number and extent of tubes inspected.

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

   c. Identification of the tubes plugged and the tubes repaired.

Deleted by TSCR 98-043

* ~~Except that the surveillance related to the steam generator tube inspection due no later than July 1996, may be deferred until the next refueling outage but no later than May 31, 1997.~~ A.6

TSCR 98-043

4. Interval of Inspection

a. The first inservice inspection of steam generators should be performed after six effective full power months but not later than completion of the first refueling outage.

b. Subsequent inservice inspections should be not less than 12 or more than 24 calendar months after the previous inspection.

SEE ITS 5.5.8

c. If the results of two consecutive inspections, not including the preservice inspection, all fall into the C-1 category, the frequency of inspection may be extended to 40-month intervals. Also, if it can be demonstrated through two consecutive inspections that previously observed degradation has not continued and no additional degradation has occurred, a 40-month inspection interval may be initiated.

B. Corrective Measures

All leaking tubes and defective tubes should be: (1) plugged, or (2) repaired.

~~C.~~ Steam Generator Tube Inspection Reports

5.6.8 1. Following each inservice inspection of steam generator tubes, the number of tubes plugged and or repaired in each steam generator shall be reported to the Commission within 15 days.

2. The complete results of the steam generator tube inservice inspection shall be reported in writing on an annual basis for the period in which the inspection was completed per Specification 6.9.2 5.5.8. This report shall include:

a. Number and extent of tubes inspected.

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

c. Identification of the tubes plugged and the tubes repaired.

TSCR 98-043

5.5.8.e.3 ~~5.~~ Results of steam generator tube inspections which fall into Category C-3 of Table 4.9-1 require notification of the Commission within 15 days of this determination*. ~~The written followup of this report shall provide a description of investigations conducted to determine cause of the tube degradation and corrective measures taken to prevent recurrence.~~

5.5-1

A.7

5.5.8.e.4 ~~* Note~~ Table 4.9-1 requires NRC approval prior to startup in one case.

5.5-1

~~BASIS~~

~~Inservice surveillance of steam generator tubes is essential in order to ensure that the structural integrity of this portion of the RCS is maintained. This inservice surveillance consists of an inspection program which provides a means of identifying and characterizing the nature of any mechanical damage or tube degradation so that corrective measures can be taken. Degradation could be caused by design or fabrication deviations or inservice conditions that lead to corrosion.~~

~~An essentially 100% tube inspection was performed on each tube in every steam generator by eddy current techniques prior to service in order to establish a baseline condition for the tubing. This inspection was conducted under conditions and with equipment and techniques equivalent to those expected to be employed in the subsequent inservice inspections.~~

A.1

~~The program for inservice inspection of steam generator tubes including equipment, procedures, and sample selection is based upon the guidance and recommendations in Regulatory Guide 1.83 and NRC Generic letter 85-02. The program includes a full length inspection for the initial 3% sample recommended in the regulatory guide followed by supplementary tube sampling and inspection if necessary based upon the results of the initial sample. The initial sample inspection may include separate entries from the hot and cold leg sides to satisfy the minimum sampling requirements. Supplementary inspections need not be full length and should concentrate on areas of known degradation. The detailed sampling process based upon the regulatory guide is defined in section 4.9.A.2, 4.9.A.3, and Table 4.9-1 of this section, and the frequency of inspection in 4.9.A.4.~~

~~Following the pre-service inspection, the plant is expected to be operated in a manner such that the secondary coolant will be maintained within those limits~~

(A.1)

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 result in stress corrosion cracking. If stress corrosion cracking occurs during plant operation, its extent would be limited by the limitation of steam generator tube leakage between the primary coolant system and the secondary coolant system which is 500 gallons per day per steam generator. Cracks having a primary to secondary leakage less than this limit during operation have an adequate margin of safety against failure due to loads imposed by design basis accidents. Operating plants have demonstrated that primary to secondary leakage as low as 0.1 gpm can be detected. Leakage in excess of the 500 gallon per day per steam generator limit requires plant shutdown and an unscheduled inspection, during which the leaking tubes will be located and plugged or repaired. This limit is also consistent with the assumptions used to develop the Technical Specification limit for secondary coolant activity. For Indian Point 3, for conservatism, the plant will be shutdown if leakage exceeds 432 gallons per day per steam generator or 1 gpm total through all four steam generators and an unscheduled eddy current inspection will be conducted. Leaking and defective tubes will be located and either; (1) plugged or (2) repaired.

If the results of an inservice inspection conducted as described previously show any tube with an imperfection exceeding 40% of the tube nominal wall thickness, the tube is unacceptable for continued operation and must be plugged or repaired as required by the ASME Code. Steam generator tube inspections of operating plants have demonstrated the capability to reliably detect degradation that has penetrated 20% of the original 0.050 inch nominal wall thickness. In accordance with Regulatory Guide 1.121, a plugging margin evaluation has demonstrated that the actual remaining wall thickness for flaws with axial extent not exceeding 0.9 inches and circumferential extent not exceeding 135° to withstand the max DP expected during faulted conditions is 28%. This is also supported by burst test data of representative tubing. Leak before break has also been verified for this extent of degradation. Since this provides for 72% wall loss, a 40% plugging limit incorporates a 32% margin. A 10% margin is applied to measurement inaccuracies leaving 22% safety margin for corrosion allowance during a given operating period prior to the next inspection.

TABLE 4.9-1 5.5-1 Acceptable for Service A.1

STEAM GENERATOR TUBE INSPECTION

First Sample Inspection			Second Sample Inspection		Third Sample Inspection	
Minimum Size	Result	Action	Result	Action	Result	Action
S* Tubes per steam generator	C-1					
	C-2	Plug or repair defective tubes. Inspect additional 2S tubes in this SG.	C-1			Go to power
			C-2	Plug or repair defective tubes. Inspect additional 4S tubes in this SG.	C-1	
					C-2	Plug or repair defective tubes. Go to power.
					C-3	Go to first sample. C-3 action
			C-3	Go to first sample. C-3 action		
	C-3	Inspect all tubes in this SG. Plug or repair defective tubes. Inspect 2S tubes in each other SG	All other SGs C-1			Go to power
			Some SGs C-2 But no add'l C-3	Go to second sample. C-2 action		
			Add'l SG C-3	Inspect all tubes in all SGs. Plug or repair defective tubes.		Report to NRC. NRC approval req'd prior to startup

(con't)

ITS 5.5

~~(con't)~~

Table 5.5-1

12 — A.1

*S = 3 N/n % where N is the number of steam generators in the plant, and n is the number of steam generators inspected to satisfy the full length inspection criteria of 4.9.A.1.

5.5.8.d.2

Category C-1: Less than 5% of the total tubes inspected are degraded tubes and none are of them is defective. A.1

Category C-2: One or more of the total tubes inspected is defective but not more than 1% ~~of the tubes~~ inspected or between 5 and 10% of the tubes inspected are degraded tubes.

Category C-3: More than 10% of the total tubes inspected are degraded or more than 1% of the tubes inspected are defective.

ITS 5.5.8

4.10 SEISMIC INSTRUMENTATION

Applicability

Applies to testing of seismic monitoring instruments.

Objective

To verify that the subject systems will respond promptly and perform their design functions, if required.

Specification

4.10.1 Each of the seismic monitoring instruments in Table 4.10-1 shall be demonstrated OPERABLE by the performance of the CHANNEL CHECK, CHANNEL CALIBRATION, and CHANNEL FUNCTIONAL TEST operations at the frequencies shown in Table 4.10-2.

4.10.2 If the number of OPERABLE seismic monitoring instruments is less than that required by Table 4.10-1, restore the inoperable instrument(s) to OPERABLE status within 30 days.

4.10.3 With one or more seismic monitoring instruments inoperable for more than 30 days, prepare and submit a Special Report to the Commission pursuant to Specification 6.9.2 within the next 10 days outlining the cause of the malfunction and the plans for restoring the instrument(s) to OPERABLE status.

4.10.4 Each of the seismic monitoring instruments actuated during a seismic event shall be restored to OPERABLE status and a CHANNEL CALIBRATION performed within 48 hours following the seismic event. Data shall be retrieved from actuated instruments and analyzed to determine the magnitude of the vibratory ground motion. A Special Report shall be prepared and submitted to the Commission pursuant to Specification 6.9.2 within 10 days describing the magnitude, frequency spectrum and resultant effect upon facility features important to safety.

R.20

~~**Basis**~~

~~The OPERABILITY of the seismic instrumentation ensures that sufficient capability is available to promptly determine the magnitude of a seismic event and evaluate the response of those features important to safety. This capability is required to permit comparison of the measured response to that used in the design basis for the facility and is consistent with the recommendations of Regulatory Guide 1.12, "Instrumentation for Earthquakes", April, 1974.~~

R.20

TABLE 4.10-1

SEISMIC MONITORING INSTRUMENTATION

INSTRUMENTS AND SENSOR LOCATIONS	MEASUREMENT RANGE	MINIMUM INSTRUMENTS OPERABLE
1. Triaxial Time-History Accelographs		
a. EL 46'-0" VC Base Mat	0 to ± 1G	1*
b. EL 99'-0" VC Wall	0 to ± 1G	1*
2. Triaxial Peak Accelographs		
a. STM GEN # 31	0 to ± 2G	1
b. RC Pump # 31	0 to ± 2G	1
c. Pressurizer	0 to ± 2G	1
3. Triaxial Response-Spectrum Recorders		
a. EL 46'-0" VC Base Mat	0 to ± 1G	1*

R.20

* With reactor control room indication

TABLE 4.10-2

SEISMIC MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS

INSTRUMENTS AND SENSOR LOCATION	CHANNEL CHECK	CHANNEL CALIBRATION	CHANNEL FUNCTIONAL TEST
1. Triaxial Time-History Accelographs			
a. EL 46' -0" VC Base Mat	M*	24M	SA
b. EL 99' -0" VC Wall	M*	24M	SA
2. Triaxial Peak Accelographs			
a. STM GEN #31	NA	24M	NA
b. RC Pump #31	NA	24M	NA
c. Pressurizer	NA	24M	NA
3. Triaxial Response-Spectrum Recorders			
a. EL 46' -0" VC Base Mat**	M	24M	SA

24M - At least once per 24 months

---

* Except seismic trigger

** With reactor control room indications.

R.20

Relocated Item (R-17)

4.11 SAFETY-RELATED SHOCK SUPPRESSORS (SNUBBERS)

Applicability

Applies to the periodic inspection and testing requirements for all safety-related hydraulic snubbers that are required to protect the primary coolant system or any other safety-related system or component.

Objective

To verify that safety-related snubbers will perform their design functions in the event of a seismic or other transient dynamic event.

Specification

A. Visual Inspection

1. Safety-related snubbers shall be visually inspected in accordance with the following schedule:

Size of Population or Category (Notes 1 & 2)	Number Of Unacceptable Snubbers		
	Column A Extend Interval (Note 3)	Column B Repeat Interval (Note 4)	Column C Reduce Interval (Note 5)
1	0	0	1
20	0	0	1
40	0	0	1
60	0	0	1
80	0	0	2
90	0	0	3
100	0	1	4
120	0	1	5
130	0	2	6
140	0	2	7
150	0	3	8
160	0	3	9
170	0	3	10
180	1	4	11
190	1	4	12
200	2	5	13

Amendment No. ~~6~~,~~57~~,~~83~~, 111,

R.17

Note 1: The next visual inspection interval for a snubber population or category size shall be determined based upon the previous inspection interval and the number of unacceptable snubbers found during that interval. Snubbers may be categorized, based upon their accessibility during power operation, as accessible or inaccessible. These categories may be examined separately or jointly. This decision shall be made and documented before any inspection and shall be used as the basis upon which to determine the next inspection interval for that category.

Note 2: Interpolation between population or category sizes and the number of unacceptable snubbers is permissible. The next lower integer for the value of the limit for Columns A, B, C shall be used if that integer includes a fractional value of unacceptable snubbers as determined by interpolation.

Note 3: If the number of unacceptable snubbers is equal to or less than the number in Column A, the next inspection interval may be twice the previous interval but not greater than 48 months.

Note 4: If the number of unacceptable snubbers is equal to or less than the number in Column B, but greater than the number in Column A, the next inspection interval shall be the same as the previous interval.

Note 5: If the number of unacceptable snubbers is equal to or greater than the number in Column C, the next inspection interval shall be two-thirds of the previous interval. However, if the number of unacceptable snubbers is less than the number in Column C, but greater than the number in Column B, the next interval shall be reduced by a factor that is one-third of the ratio of the difference between the number of unacceptable snubbers found during the previous interval and the number in Column B to the difference in the numbers in Column B and C.

R.17

2. Visual inspection shall verify (1) that there are no visible indications of damage or impaired OPERABILITY, and (2) attachments to the foundations or supporting structure are secure. Snubbers which appear inoperable as a result of visual inspections shall be classified as unacceptable and may be reclassified acceptable for the purpose of establishing the next visual inspection interval, provided that (1) the cause of the rejection is clearly established and remedied for the particular snubber and for other snubbers that may be generically susceptible; and (2) the affected snubber is functionally tested in the as found condition and determined OPERABLE per Specification 4.11.B.5. However, when the fluid port of a hydraulic snubber is found to be uncovered, the snubber shall be declared inoperable via functional testing for the purpose of establishing the next visual inspection period. All snubbers connected to an inoperable common hydraulic fluid reservoir shall be counted as inoperable snubbers.

B. Functional Testing

1. At least once per 24 months* during plant shutdown, a representative sample of 10% of all the safety-related hydraulic snubbers shall be functionally tested for operability, either in place or on a bench test. For each snubber that does not meet the requirement of 4.11.B.5, an additional 10% of the total installed of that type of hydraulic snubber shall be functionally tested. This additional testing will continue until no failures are found or until all snubbers of the same type have been functionally tested. The representative sample shall include each size and type of snubber in use in the plant.

2. The representative sample selected for functional testing should include the various configurations, operating environments, sizes and capacities of snubbers. At least 25% or the maximum possible if less than 25%, of the snubbers in the representative sample should include snubbers from the following three categories:

   a. The first snubber away from each reactor vessel nozzle.

* Snubber functional testing due no later than May 1996 may be deferred until the next refueling outage but no later than May 31, 1997.

R.17

R.17

b. Snubbers within 5 feet of heavy equipment (valve, pump, turbine, motor, etc.)

c. Snubbers within 10 feet of the discharge from a safety or relief valve.

Snubbers identified as "Especially Difficult to Remove" or in "High Radiation Zones During Shutdown" shall also be included in the representative samples*.

Snubber selection for functional testing is developed from an engineering evaluation and is based on a rotating basis. In addition to the regular sample, snubber locations which failed the previous functional test shall be retested during the next test period. If a spare snubber has been installed in place of a failed snubber, then both the previously failed snubber (if it is repaired and currently installed in another position) and the installed spare snubber shall be retested. Test results of these snubbers may not be included for the sampling required by Specification 4.11.B.1.

3. If any snubber selected for functional testing either fails to lockup or fails to move, i.e., frozen in place, the cause will be evaluated and if caused by manufacturer or design deficiency all snubbers of the same manufacturer and model, subject to the same defect and located in a similar environment, shall be functionally tested.

4. For the snubber(s) found inoperable, an engineering evaluation shall be performed on the components which are supported by the snubber(s). The purpose of this engineering evaluation shall be to determine if the components supported by the inoperable snubber(s) remain capable of performing their intended function in their intended manner after the action statements of Specification 3.13.2.a or 3.13.3 a were performed as necessary.

Amendment No. ~~6~~, ~~57~~, ~~87~~, 111,

* Permanent or other exemptions from functional testing for individual snubbers in these categories may be granted by the Commission only if a justifiable basis for exemption is presented and/or snubber life destructive testing was performed to qualify snubber operability for all design conditions.

R.17

5. The hydraulic snubber functional test shall verify that:

   a. Activation (restraining action) is achieved within the specified range of velocity or acceleration in both tension and compression.

   b. Snubber bleed, or release rate, where required, is within the specified range in compression or tension. For snubbers specifically required to not displace under continuous load, the ability of the snubber to withstand load without displacement shall be verified.

C. Snubber Service Life Monitoring

1. A record of the service life of each snubber, the date at which the designated service life commences, as well as the installation and maintenance records on which the designated service life is based shall be maintained as required by specification 6.10.2.o. The service life may be modified based on a performance evaluation.

2. At least once per 24 months the installation and maintenance records for each safety-related snubber shall be reviewed to verify that the indicated service life has not been exceeded or will not be exceeded prior to the next scheduled snubber service life review. If the indicated service life will be exceeded prior to the next scheduled snubber service life review, the snubber service life shall be reevaluated or the snubber shall be replaced or reconditioned so as to extend its service life beyond the date of the next scheduled service life review. This re-evaluation, replacement or reconditioning shall be indicated in the records.

Basis

The visual inspection frequency is based upon maintaining a constant level of snubber protection to systems. Performance of periodic visual inspections of snubbers complements the existing functional testing and provides additional confidence in snubber operability. The visual inspection interval for the snubbers is based on the number of unacceptable snubbers found during the previous inspection in proportion to the sizes of the various populations or categories and may be as long as two refueling cycles with good overall visual inspection results. The visual inspection interval will not exceed 48 months. However, as for all surveillance activities, unless otherwise noted, allowable tolerances of 25% are applicable for snubbers. These tolerances are necessary to provide operational flexibility because of scheduling and performance considerations. The words "will not exceed" associated with a surveillance interval does not negate this allowable tolerance. Inspections performed before the interval has elapsed may be used as a new reference point to determine the next scheduled inspection; however, the results of such early

Relocated Item (R-17)

inspections performed before the original required time interval has elapsed may not be used to lengthen the required inspection interval. Any inspection whose results require a shorter inspection interval will override the previous schedule. The results of random inspections of individual snubbers, conducted at other than scheduled inspection intervals, will be evaluated on a case-by-case basis to determine if they should impact the scheduled interval.

When the cause of the rejection of a snubber is clearly established and remedied for that snubber and for any other snubbers that may be generically susceptible, and verified operable by inservice functional testing, that snubber may be exempted from being counted as inoperable. Generically susceptible snubbers are those which are of a specific make or model and have the same design features directly related to rejection of the snubber by visual inspection, and are similarly located or exposed to the same environmental conditions such as temperature, radiation, and vibration.

When a snubber is found inoperable, an engineering evaluation is performed, in addition to the determination of the snubber mode of failure, in order to determine if any safety-related component or system has been adversely affected by the inoperability of the snubber. The engineering evaluation shall determine whether or not the snubber mode of failure has imparted a significant effect or degradation on the supported component or system by determining if the system or component was exposed to a dynamic transient which required the inoperable snubber to mitigate the transient.

To provide assurance of snubber functional reliability, a representative sample of 10% of the installed snubbers will be functionally tested during plant shutdowns. The representative sample selected for functional testing includes various configurations, operating environments, locations and the range of size and capacity of snubbers. An engineering evaluation which addresses snubber performance environments and history selects the representative sample which is based on a rotating basis. Selection of a representative sample of hydraulic snubbers provides a confidence level within acceptable limits that these supports will be in an operable condition. Observed failures of these sample snubbers shall require functional testing of additional units of the same type.

R.17

Amendment No. ~~8~~, ~~72~~, ~~87~~, 111, If a snubber fails a functional test, that snubber location will be retested during the next snubber testing period to determine if the failure was environmentally caused. If the failed snubber was repaired and re-installed elsewhere in the system, during the functional test effort the snubber will be retested during the next testing period to verify if the repair addressed the cause of a failure. If a failed snubber is repaired and not reinstalled in the system during the functional test effort it shall be retested before it is subsequently installed in the system as added assurance that the repair addressed the cause of failure. The results of these augmented testing efforts are intended to address previous failure modes and these test results (passing or failure) may not be included in the specification 4.11.B.1 sample selection.

The service life of a snubber is evaluated via engineering evaluation, test data, service data, manufacturer input, snubber service conditions and snubber service history (newly installed snubber, seal replaced, spring replaced, in high radiation area, high temperature area, etc....). The requirement to monitor the snubber service life is included to ensure that the snubbers periodically undergo a performance evaluation in view of their age and operating conditions. These records will provide statistical bases for future consideration of snubber service life. The requirements for the maintenance of records and the snubber service life review are not intended to affect plant operation.

References

1) Generic Letter 84-13, "Technical Specifications For Snubbers."

2) Generic Letter 90-09, "Alternative Requirements For Snubber Visual Inspection Intervals and Corrective Actions."

R.17

Amendment No. ~~8~~,~~37~~,~~83~~, 111,

Add SR 3.6.3.2 — M.2

ITS 3.6.3

A.1

Pressure Relief — A.11

4.13 Containment ~~Vent~~ and Purge System

Applicability

Mode 1, 2, 3 and 4 — A4

This specification applies to the surveillance requirements of the containment vent and purge system during normal operations and when reactor fuel is anticipated to be moved before the reactor has been subcritical for at least 421* hours.

SEE ITS 3.9.3

~~Objective~~

~~To verify the operability of the containment vent and purge system.~~ — A.2

~~Specification~~

The following surveillance shall be performed as stated.

A. Isolation Valves

Mode 1, 2, 3, 4 — A.4

SR 3.6.3.1 1. Each month verify that the containment purge supply and exhaust isolation valves are closed during ~~operation above cold shutdown~~.

Pressure Relief — A.11

SR 3.6.3.7 2. At least once per 24 months verify ~~that the mechanical~~ stops on the containment vent isolation valve (PCV-1190, -1191, -1192) actuator is limited to the valve opening angle to 60° (90° = full open).

B. HEPA Filters and Charcoal Absorbers

If fuel movement is to take place before the reactor has been subcritical for at least 421* hours, the containment vent and purge system shall be demonstrated operable as follows:

1. Within 18 months prior to fuel movement and (1) after each complete or partial replacement of a HEPA filter or charcoal adsorber bank within 18 months prior to fuel movement, or (2) after structural maintenance on the HEPA filter or charcoal adsorber housing within 18 months prior to fuel movement, which could effect system operation:

SEE ITS 5.5.10

a. Verify that the charcoal adsorbers remove ≥ 99% of halogenated hydrocarbon refrigerant test gas when they are tested in-place while operating the ventilation system at the operating flow ± 10%.

b. Verifying that the HEPA filter banks remove ≥ 99% of the DOP when they are tested in-place while operating the ventilation system at the operating flow rate ± 10%.

2. Within 18 months prior to fuel movement and after every 720 hours of system operation, subject a representative sample of carbon from the charcoal adsorbers to a laboratory analysis and verify within 31 days a removal efficiency of ≥ 90% for radioactive methyl iodine at an operating air flow velocity ± 20% per test 5.b in Table 2 of Regulatory Guide 1.52, March 1978.

SEE ITS 3.9.3

* Movement of irradiated VANTAGE + fuel assemblies before the reactor has been subcritical for ≥550 hours requires operation of the Containment Building Vent and Purge System through the HEPA filters and charcoal adsorbers.

4.13 Containment Vent and Purge System

Applicability

SEE ITS 3.6.3

This specification applies to the surveillance requirements of the containment vent and purge system during normal operations and when reactor fuel is anticipated to be moved before the reactor has been subcritical for at least 421* hours. 550 A.6

Not to LCO 3.9.3.d

~~Objective~~

~~To verify the operability of the containment vent and purge system.~~ A.1

~~Specification~~

The following surveillance shall be performed as stated.

A. Isolation Valves

SEE ITS 3.6.3

1. Each month verify that the containment purge supply and exhaust isolation valves are closed during operation above cold shutdown.

2. At least once per 24 months verify that the mechanical stops on the containment vent isolation valve (PCV-1190, -1191, -1192) actuator is limited to the valve opening angle to 60° (90° = full open).

B. HEPA Filters and Charcoal Absorbers

If fuel movement is to take place before the reactor has been subcritical for at least 421* hours, the containment vent and purge system shall be demonstrated operable as follows: 550 A.6

SR 3.9.3.4

A.7

1. Within 18 months prior to fuel movement and (1) after each complete or partial replacement of a HEPA filter or charcoal adsorber bank within 18 months prior to fuel movement, or (2) after structural maintenance on the HEPA filter or charcoal adsorber housing within 18 months prior to fuel movement, which could effect system operation:

   a. Verify that the charcoal adsorbers remove $\geq$ 99% of halogenated hydrocarbon refrigerant test gas when they are tested in-place while operating the ventilation system at the operating flow $\pm$ 10%.

   b. Verifying that the HEPA filter banks remove $\geq$ 99% of the DOP when they are tested in-place while operating the ventilation system at the operating flow rate $\pm$ 10%.

SEE ITS 5.5.10, VFTP

2. Within 18 months prior to fuel movement and after every 720 hours of system operation, subject a representative sample of carbon from the charcoal adsorbers to a laboratory analysis and verify within 31 days a removal efficiency of $\geq$ 90% for radioactive methyl iodine at an operating air flow velocity $\pm$ 20% per test 5.b in Table 2 of Regulatory Guide 1.52, March 1978.

Not to LCO 3.9.3.d

* Movement of irradiated VANTAGE + fuel assemblies before the reactor has been subcritical for ≥550 hours requires operation of the Containment Building Vent and Purge System through the HEPA filters and charcoal adsorbers. A.5

4.13 Containment Vent and Purge System

A.2

Applicability

This specification applies to the surveillance requirements of the containment vent and purge system during normal operations and when reactor fuel is anticipated to be moved before the reactor has been subcritical for at least 421 hours.

Objective

To verify the operability of the containment vent and purge system.

Specification

The following surveillance shall be performed as stated.

SEE ITS 3.6.3

~~A.~~ Isolation Valves

1. Each month verify that the containment purge supply and exhaust isolation valves are closed during operation above cold shutdown.

2. At least once per 24 months verify that the mechanical stops on the containment vent isolation valve (PCV-1190, -1191, -1192) actuator is limited to the valve opening angle to 60° (90° = full open).

SEE ITS 3.9.3

~~B.~~ HEPA Filters and Charcoal Absorbers

SEE CTS · RELOCATED

If fuel movement is to take place before the reactor has been subcritical for at least 421 hours, the containment vent and purge system shall be demonstrated operable as follows:

5.5.10 1. Within 18 months prior to fuel movement and (1) after each complete or partial replacement of a HEPA filter or charcoal adsorber bank within 18 months prior to fuel movement, or (2) after structural maintenance on the HEPA filter or charcoal adsorber housing within 18 months prior to fuel movement, which could effect system operation:

painting, fire or chemical release

A.1

M.2

5.5.10.b a. Verify that the charcoal adsorbers remove ≥ 99% of halogenated hydrocarbon refrigerant test gas when they are tested in-place while operating the ventilation system at the operating flow ± 10%.

5.5.10.a ~~b.~~ Verifying that the HEPA filter banks remove ≥ 99% of the DOP when they are tested in-place while operating the ventilation system at the operating flow rate ± 10%.

2. Within 18 months prior to fuel movement and after every 720 hours of system operation, subject a representative sample of carbon from the charcoal adsorbers to a laboratory analysis and verify within 31 days a removal efficiency of ≥ 90% for radioactive methyl iodine at an operating air flow velocity ± 20% per test 5.b in Table 2 of Regulatory Guide 1.52, March 1978.

5.5.10.c

A.3

5.5.10.a
5.5.10.b

Add requirement for visual inspection per C.5.a of R.G.1.52, R2

M.1

~~Basis~~

~~The containment purge supply and exhaust isolation valves are required to be closed during plant operation above cold shutdown. Containment purge supply or exhaust isolation valve closure may be verified by way of the position indication lights, the weld channel and penetration pressurization system or visual means. The maximum opening angle of the containment vent isolation valves is being limited as an analysis demonstrates valve operability against accident containment pressures provided the valves are limited to an opening angle of 60°.~~

~~The operability of the HEPA filter and charcoal absorber system and the resulting iodine removal capacity are consistent with accident analyses. The representative carbon sample will be two inches in diameter with a length equal to the thickness of the bed.~~

A.1

~~Basis~~

A.1

~~The containment purge supply and exhaust isolation valves are required to be closed during plant operation above cold shutdown. Containment purge supply or exhaust isolation valve closure may be verified by way of the position indication lights, the weld channel and penetration pressurization system or visual means. The maximum opening angle of the containment vent isolation valves is being limited as an analysis demonstrates valve operability against accident containment pressures provided the valves are limited to an opening angle of 60°.~~

~~The operability of the HEPA filter and charcoal absorber system and the resulting iodine removal capacity are consistent with accident analyses. The representative carbon sample will be two inches in diameter with a length equal to the thickness of the bed.~~

4.0 ~~5.~~ DESIGN FEATURES

4.1 ~~5.1~~ SITE

~~Applicability~~

~~Applies to the location and extent of the reactor site.~~ A.2

~~Objective~~

~~To define those aspects of the site which affect the overall safety of the installation.~~

4.1 ~~Specification~~ Add Site Location A.3

4.1 The minimum distance from the reactor center line to the boundary of the site exclusion area and the outer boundary of the low population zone as defined in 10 CFR 100.3 is 350 meters ⊗ and 1100 meters, ⊗ respectively.

~~References~~

~~(1) FSAR - Section 2.4.4~~

~~(2) FSAR - Section 2.4.3~~ A.1

5.2 CONTAINMENT

A.2

~~**Applicability**~~

~~Applies to those design features of the Containment System relating to operational and public safety.~~

~~**Objective**~~

~~To define the significant design features of the reactor containment structure.~~

LA.1

~~**Specifications**~~

~~A. Reactor Containment~~

~~1. The reactor containment completely encloses the entire reactor and reactor coolant system and ensures that an acceptable upper limit for leakage of radioactive materials to the environment is not exceeded even if gross failure of the reactor coolant system occurs. The structure provides biological shielding for both normal and accident situations.~~

~~2. The containment structure is designed for an internal pressure of 47 psig, plus the loads resulting from an earthquake producing 0.15g applied horizontally and 0.10g applied vertically at the same time.(1) The containment is also structurally designed to withstand an external pressure 3 psig higher than the internal pressure.~~

~~B. Penetrations~~

~~1. All penetrations through the containment reinforced concrete pressure barrier for pipe, electrical conductors, ducts and access hatches are of the double barrier type.(2)~~

LA.1

2. The automatic Phase A containment isolation valves are actuated to the closed position by an automatically derived safety injection signal. A manually initiated containment isolation signal can be generated from the control room to perform the same function. The automatic Phase B containment isolation valves are tripped closed upon actuation of the containment spray system. The actuation system is designed such that no single component failure will prevent containment isolation if required.

C. Containment Systems

1. The containment vessel has two internal spray sub-systems each of which is capable of providing a distributed borated water spray of at least 2500 gpm. During the initial period of spray operation, sodium hydroxide would be added to the spray water to increase the removal of iodine from the containment atmosphere.(3)

2. The containment vessel has an internal air recirculation system which includes five fan-cooler units (centrifugal fans and water cooled heat exchangers), each capable of transferring heat at a rate of 21,200 BTU/sec from the containment atmosphere at the post accident design conditions, i.e., a saturated air-steam mixture at 47 psig and 271°F. All of the fan cooler units are equipped with activated charcoal filters to remove volatile iodine following an accident.(4)

References

(1) FSAR Appendix 5A
(2) FSAR Section 5.1.2.7
(3) FSAR Section 6.3
(4) FSAR Section 6.4

~~5.3 REACTOR~~

~~Applicability~~

~~Applies to the reactor core, and reactor coolant system.~~

~~Objective~~

~~To define those design features which are essential in providing for safe system operations.~~

A.2

4.2 ~~A.~~ Reactor Core natural A.6

4.2.1 1. The reactor core contains ~~approximately 89 metric tons of~~ uranium in the form of slightly enriched uranium dioxide ~~pellets~~ fuel assemblies. The pellets are encapsulated in Zircaloy-4 or ZIRLO™ tubing to form fuel rods. The reactor core is made up of 193 fuel assemblies. Limited substitutions of zirconium alloy or stainless steel filler rods for fuel rods, in accordance with approved applications of fuel rod configurations, may be used. Fuel assemblies shall be limited to those fuel designs that have been analyzed with applicable NRC staff approved codes and methods and shown by tests or analyses to comply with all fuel safety design bases. A.4 A.6

~~2. The average enrichment of the initial core was a nominal 2.8 weight percent of U-235. Three fuel enrichments were used in the initial core. The highest enrichment was a nominal 3.3 weight percent of U-235.[2]~~ A.4

~~3. Reload fuel will be similar in design to the initial core.~~

4.2.1 The enrichment of reload fuel will be no more than 5.0 weight percent of U-235.

~~4. Burnable poison rods were incorporated in the initial core. There were 1434 poison rods in the form of 8, 9, 12, 16, and 20-rod clusters, which are located in vacant rod cluster control guide tubes.[3] The burnable poison rods consist of borosilicate glass clad with stainless steel.[4] Burnable poison rods of an approved design may be used in reload cores for reactivity and/or power distribution control.~~ A.4

Add 4.2.1 allowance for lead test assemblies. A.5

Amendment No. ~~61, 70, 90, 104, 117, 118,~~ 173

TSCR 97083

Amendment 175 not shown: Superceded by TSCR 97-083

4.2.2 ~~5.~~ There are 53 control rods in the reactor core. The control rods contain ~~142 inch lengths of~~ silver-indium-cadmium alloy clad ~~with the stainless steel~~.[5] as approved by NRC (LA.1) (A.

B. ~~Reactor Coolant System~~

~~1. The design of the reactor coolant system complies with the code requirements.[6]~~

~~2. All piping, components and supporting structures of the reactor coolant system are designed to Class I requirements, and have been designed to withstand the maximum potential seismic ground acceleration, 0.15g, acting in the horizontal and 0.10g acting in the vertical planes simultaneously with no loss of function.~~ (LA.1)

~~3. The nominal liquid volume of the reactor coolant system, at rated operating conditions and with 0% equivalent steam generator tube plugging, is 11,522 cubic feet.~~

Basis

~~The fuel assembly reconstitution methodology, WCAP 13060-P-A, has been NRC staff approved as shown by tests or analyses to comply with all fuel safety design bases.~~

Deleted by Amendment 175

~~References~~

~~(1) FSAR Section 3.2.2~~

~~(2) FSAR Section 3.2.1~~

~~(3) FSAR Section 3.2.1~~

~~(4) FSAR Section 3.2.3~~

~~(5) FSAR Sections 3.2.1 & 3.2.3~~

~~(6) FSAR Table 4.1-9~~

TSCR 97-083

Amendment 175

5.4 FUEL STORAGE

A.2

~~Applicability~~

~~Applies to the capacity and storage arrays of new and spent fuel.~~

~~Objective~~

~~To define those aspects of fuel storage relating to prevention of criticality in fuel storage areas.~~

Specification

SEE ITS SECTION 4.0

1. The spent fuel pit structure is designed to withstand the anticipated earthquake loadings as a Class I structure. The spent fuel pit has a stainless steel liner to insure against loss of water.

2. The spent fuel storage racks are designed to assure $K_{eff} \leq 0.95$ if the assemblies are inserted in accordance with Technical Specification 3.8. The capacity of the spent fuel pit is 1345 assemblies with the maximum density storage racks installed. The new fuel storage racks are designed to assure $K_{eff} \leq 0.95$ under all possible moderation conditions. The capacity of the new fuel racks is 72 assemblies containing fuel pellets enriched to a maximum 5.0 weight percent of U-235 and a maximum K_{eff} (in infinite array) of each fuel assembly of 0.95. Credit may be taken for burnable integral neutron absorbers.

LCO 3.7.15 Applicability

3. Whenever ~~there is fuel in the pit (except in the initial core loading)~~, the spent fuel storage is filled and borated to the concentration ~~to match that used in the reactor cavity and refueling canal during refueling operations~~.

SEE ITS SECTION 4.0

4. Fuel assemblies that contain pellets enriched to greater than 5.0 weight percent of U-235 shall not be stored in the spent fuel pit or new fuel racks.

Add LCO 3.7.15 Applicability L.1

A.3

1000 ppm A.4

5.4 FUEL STORAGE

A.2

~~Applicability~~

~~Applies to the capacity and storage arrays of new and spent fuel.~~

~~Objective~~

~~To define those aspects of fuel storage relating to prevention of criticality in fuel storage areas.~~

Specification

LA1

1. ~~The spent fuel pit structure is designed to withstand the anticipated earthquake loadings as a Class I structure. The spent fuel pit has a stainless steel liner to insure against loss of water.~~

4.3.1.1.b 2. The spent fuel storage racks are designed to assure $K_{eff} \leq 0.95$ ~~if the assemblies are inserted in accordance with Technical Specification 3.8.~~ A.
4.3.3 The capacity of the spent fuel pit is 1345 assemblies with the maximum density storage racks installed.
4.3.1.2.b The new fuel storage racks are designed to assure $K_{eff} \leq 0.95$ under all possible moderation conditions. ~~The capacity of the new fuel racks is 72 assemblies containing fuel pellets enriched to a maximum 5.0 weight percent of U-235 and a maximum K_{eff} (in infinite array) of each fuel assembly of 0.95.~~ LA
4.3.1.2.b Credit may be taken for burnable integral neutron absorbers.

SEE ITS 3.7.15 3. Whenever there is fuel in the pit (except in the initial core loading), the spent fuel storage is filled and borated to the concentration to match that used in the reactor cavity and refueling canal during refueling operations.

<4.3.1.1.a>
<4.3.1.2.a>
~~4.~~ Fuel assemblies that contain pellets enriched to greater than 5.0 weight percent of U-235 shall not be stored in the spent fuel pit or new fuel racks.

Add ITS 4.3.1.1.c and 4.3.1.1.d — A.8

Add ITS 4.3.1.2.c — A.8

Add ITS 4.3.2, Spent Fuel Pool Design Level — A.8

Amendment No. 13, 34, 70, 90, 173

5.0 ~~6.0~~ ADMINISTRATIVE CONTROLS

5.1 6.1 RESPONSIBILITY

5.1.1 ~~6.1.1~~ The ~~Site Executive Officer~~ plant manager shall be responsible for overall facility operation. During periods when the ~~Site Executive Officer~~ is unavailable, ~~one of the General Managers will assume his responsibilities or the Site Executive Officer may~~ delegate this responsibility ~~to other qualified supervisory personnel~~. shall in writing

LA.1

M

SEE ITS 5.2

6.2 ORGANIZATION

6.2.1 Facility Management and Technical Support

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

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

b) The Site Executive Officer shall be responsible for overall unit safe operation and shall have control over those onsite activities necessary for safe operation and maintenance of the plant.

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

Add ITS 5.1.1, Second Paragraph — M.2

Add ITS 5.1.2 — M.3

6.0 ADMINISTRATIVE CONTROLS

SEE ITS 5.1

6.1 RESPONSIBILITY

6.1.1 The Site Executive Officer shall be responsible for overall facility operation. During periods when the Site Executive Officer is unavailable, one of the General Managers will assume his responsibilities or the Site Executive Officer may delegate this responsibility to other qualified supervisory personnel.

5.2 ~~6.2~~ ORGANIZATION

5.2.1 6.2.1 Facility Management and Technical Support

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

5.2.1.a a) Lines of authority, responsibility, and communication shall be established and defined for the highest management levels through intermediate levels to and including all operating organization positions. These relationships shall be documented and updated, as appropriate, in the form of organization charts, functional descriptions of departmental responsibilities and relationships, and job descriptions for key personnel positions, or in equivalent forms of documentation. These requirements shall be documented in the Updated FSAR. include plant specific titles and LA.1

plant manager

5.2.1.b b) The ~~Site Executive Officer~~ shall be responsible for overall unit safe operation and shall have control over those onsite activities necessary for safe operation and maintenance of the plant. LA.1

5.2.1.c c) The ~~Chief Nuclear Officer~~ shall have corporate responsibility for overall plant nuclear safety and shall take any measures needed to ensure acceptable performance of the staff in operating, maintaining, and providing technical support to the plant to ensure nuclear safety. LA.1

Corporate officer with direct responsibility for the plant

Amendment No. 19, 22, 38, 39, 59, 89, 116, 136, 162, 163

A.1

<5.2.1.d> ~~d)~~ The individuals who train the operating staff and those who carry out health physics and quality assurance functions may report to the appropriate onsite manager; however, they shall have sufficient organizational freedom to ensure their independence from operating pressures.

<5.2.2> ~~6.2.2~~ PLANT STAFF

LA.2

a) Each duty shift shall be composed of at least the minimum shift crew composition shown in Table 6.2-1. LA.3

<5.2.2.b> ~~b)~~ At least one Licensed Operator shall be in the control room when fuel is in the reactor.

One RO and one SRO

<5.2.2.b> ~~c)~~ At least two Licensed Operators shall be present in the control room during reactor start-up, scheduled reactor shutdown and during recovery from reactor trips. A.2

Mode 1, 2, 3 and 4

<5.2.2.d> ~~d)~~ An individual qualified in radiation protection procedures shall be on site when fuel is in the reactor. Add unexpected absence L.2

e) ALL CORE ALTERATIONS shall be directly supervised by an individual holding either a Senior Reactor Operator license or a Senior Reactor Operator license Limited to Fuel Handling who has no other concurrent responsibilities during this operation. LA.2

~~f) Deleted.~~ A.1

Add ITS 5.2.2.e, overtime review requirements

Add ITS 5.5.2.e, requirement for Procedural Controls

ITS 5.2

M.1

A.3

5.2.2.e g) Adequate shift coverage shall be maintained without routine heavy use of overtime. The objective shall be to have operating personnel work a normal 8 to 12 hour day, nominal 40-hour week while the unit is operating. (Operating personnel are defined as on shift senior reactor operators, reactor operators, nuclear plant operators, shift technical advisors and shift contingency health physicists, I&C and maintenance personnel.) A.3 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 modification 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 168 hour period, all excluding shift turnover time.

3. A break of at least 8 hours should be allowed between work periods, shift turnover time can be included in the breaktime.

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.

plant manager LA.1

Any deviation from the above guidelines shall be authorized by the ~~Site Executive Officer~~ or his designee, or higher levels of management, in accordance with established procedures.

h) At least one individual holding a Senior Reactor Operator (SRO) license shall be on duty in ~~the Control Room at all times~~ Mode 1,2,3&4 L.1

i) The Assistant Operations Manager ~~and Shift Manager shall hold a Senior Reactor Operator (SRO) license. The~~ A.4 Operations Manager shall either hold an SRO license or shall have held an SRO license at Indian Point Unit 3.*

or L.3

A.5

* ~~For the period ending three years after restart from the 1993/1994 Performance Improvement Outage, the Operations Manager will be permitted to have held an SRO license at a Pressurized Water Reactor other than Indian Point Unit 3.~~

Amendment No. ~~5, 12, 15, 19, 29, 66, 71, 85, 89, 116, 136, 147, 162, 163,~~ 181

LA.2

LA.3

TABLE 6.2-1

MINIMUM SHIFT CREW COMPOSITION*			
License Category	During Operations Involving Core Alterations	During Cold Shutdown or Refueling Periods	At All Other Times
Senior Operator License	2**	1	2
Operator License	1	1	2
Non-Licensed	(As Required)	1	2
Shift Technical Advisor	None Required	None Required	1

* Shift crew composition may be less than the minimum requirements 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 this Table.

** ~~Includes individual with SRO license supervising fuel movement as per Section 6.2.2e.~~

LA.2

5.2.2.c

5.2.2.g

5.2.2.a

SEE ITS 5.3

6.3 PLANT STAFF QUALIFICATIONS

6.3.1 Each member of the plant staff shall meet or exceed the minimum qualifications of ANSI N18.1-1971 for comparable positions, except for (1) the Radiological and Environmental Services Manager who shall meet or exceed the qualifications of Regulatory Guide 1.8, September 1975; (2) the Shift Technical Advisor who shall have a bachelor's degree or equivalent in a scientific or engineering discipline with specific training in plant design and response and analysis of the plant for transients and accidents; and (3) the Operations Manager who shall meet or exceed the minimum qualifications of ANSI N18.1-1971 except for the SRO license requirement which shall be in accordance with Technical Specification 6.2.2.i.

SEE ITS 5.2

SEE ITS 5.3

6.4 TRAINING

6.4.1 A retraining and replacement training program for the plant staff shall be maintained under the direction of the Training Manager and shall meet or exceed the requirements and recommendations of Section 5.5 of ANSI N18.1-1971 and 10 CFR Part 55.59.

6.4.2 Deleted.

SEE ITS 5.5.3

6.4.3 A training program for use of the post-accident sampling system shall be maintained to ensure that the plant has the capability to obtain and analyze reactor coolant and containment atmosphere samples under post-accident conditions.

6.4.4 A training program shall be maintained to ensure that the plant has the capability to collect and analyze or measure representative samples of radioactive iodines and particulates in plant gaseous effluent during and following an accident.

ITS 5.1

~~6.5 REVIEW AND AUDIT~~

~~Review requirements are accomplished by using qualified safety/designated technical reviewers and two separate review committees. The Plant Operating Review Committee (PORC) is an onsite review group; the Safety Review Committee (SRC) is an independent offsite review and audit group.~~

~~6.5.0 REVIEW AND APPROVAL OF PROGRAMS AND PROCEDURES~~

~~6.5.0.1 The procedure review and approval process shall be controlled and implemented by administrative procedure(s).~~

LA.2

SEE ITS 5.3

6.3 PLANT STAFF QUALIFICATIONS

6.3.1 Each member of the plant staff shall meet or exceed the minimum qualifications of ANSI N18.1-1971 for comparable positions, except for (1) the Radiological and Environmental Services Manager who shall meet or exceed the qualifications of Regulatory Guide 1.8, September 1975; (2) the Shift Technical Advisor who shall have a bachelor's degree or equivalent in a scientific or engineering discipline with specific training in plant design and response and analysis of the plant for transients and accidents; and (3) the Operations Manager who shall meet or exceed the minimum qualifications of ANSI N18.1-1971 except for the SRO license requirement which shall be in accordance with Technical Specification 6.2.2.i.

SEE ITS 5.2

6.4 TRAINING

6.4.1 A retraining and replacement training program for the plant staff shall be maintained under the direction of the Training Manager and shall meet or exceed the requirements and recommendations of Section 5.5 of ANSI N18.1-1971 and 10 CFR Part 55.59.

6.4.2 Deleted.

5.5.3 5.5.3.a ~~6.4.3~~ A training program for use of the post-accident sampling system shall be maintained to ensure that the plant has the capability to obtain and analyze reactor coolant and containment atmosphere samples under post-accident conditions.

5.5.3 5.5.3.a ~~6.4.4~~ A training program shall be maintained to ensure that the plant has the capability to collect and analyze or measure representative samples of radioactive iodines and particulates in plant gaseous effluent during and following an accident.

SEE ITS 5.1

6.5 REVIEW AND AUDIT

Review requirements are accomplished by using qualified safety/designated technical reviewers and two separate review committees. The Plant Operating Review Committee (PORC) is an onsite review group; the Safety Review Committee (SRC) is an independent offsite review and audit group.

6.5.0 REVIEW AND APPROVAL OF PROGRAMS AND PROCEDURES

6.5.0.1 The procedure review and approval process shall be controlled and implemented by administrative procedure(s).

6.5.0.2 Each program and procedure required by Technical Specification 6.8 and other procedures that affect nuclear safety, and changes thereto, shall be reviewed by a minimum of two designated technical reviewers who are knowledgeable in the affected functional area.

6.5.0.3 Designated technical reviewers shall meet or exceed the qualifications described in Section 4 of ANSI N18.1-1971 for applicable positions, with the exclusion of the positions identified in Sections 4.3.2 and 4.5. Individuals whose positions are described in Sections 4.3.2 and 4.5 may qualify as designated technical reviewers provided they meet the qualifications described in other portions of Section 4.

6.5.0.4 The designated technical reviewers shall determine the need for cross disciplinary reviews. Individuals performing cross disciplinary reviews shall meet the same qualifications required for designated technical reviewers.

6.5.0.5 Each program and procedure required by Technical Specification 6.8 and other procedures that affect nuclear safety, and changes thereto, shall be reviewed from a safety perspective by a qualified safety reviewer. Safety and/or environmental impact evaluations, when required, shall be reviewed by PORC per Technical Specification 6.5.1.6.a.

6.5.0.6 Nuclear safety related procedures and procedure changes shall be reviewed and approved, prior to implementation, by the appropriate member(s) of management. LA.2

6.5.0.7 All changes to the Process Control Program (PCP) and the Offsite Dose Calculation Manual (ODCM) shall be reviewed by PORC and accepted by the Site Executive Officer prior to implementation.

6.5.1 <u>PLANT OPERATING REVIEW COMMITTEE (PORC)</u>

<u>FUNCTION</u>

6.5.1.1 The Plant Operating Review Committee shall function to advise the Site Executive Officer on all matters related to nuclear safety and all matters which could adversely change the plant's environmental impact.

<u>COMPOSITION</u>

6.5.1.2 The Plant Operating Review Committee shall be composed of a Chairman, Vice Chairman and members designated in writing by the Site Executive Officer. Members shall collectively have responsibility in at least the areas of operations, maintenance, radiation safety, chemistry, engineering, instrumentation and controls, reactor engineering, nuclear licensing, and quality assurance.

ALTERNATES

6.5.1.3 All alternate members shall be appointed in writing by the (PORC) Chairman to serve on a temporary basis.

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 A quorum of the PORC shall consist of the Chairman or Vice Chairman, and at least five members including alternates. Vice-Chairmen may act as members when not acting as Chairman. A quorum shall contain no more than two alternates.

RESPONSIBILITIES

6.5.1.6 The Plant Operating Review Committee shall be responsible for:

a. Review of 10 CFR 50.59 safety and environmental impact evaluations associated with procedures and programs required by Technical Specification 6.8, and changes thereto.

b. Review of all proposed tests and experiments that affect nuclear safety. LA.2

c. Review of all proposed changes to the Operating License and Technical Specifications.

d. Review of all proposed changes or modifications to plant systems or equipment that affect nuclear safety.

e. Review of changes to the PROCESS CONTROL PROGRAM and the OFFSITE DOSE CALCULATION MANUAL.

f. 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 Executive Officer, who will forward the report to the Chief Nuclear Officer, Vice President Regulatory Affairs and Special Projects, and the Chairman of the Safety Review Committee.

g. Review of all reportable events.

h. Review of facility operations to detect potential nuclear safety hazards.

i. Performance of special reviews, investigations or analyses and reports thereon as requested by the Site Executive Officer or the Chairman of the Safety Review Committee (SRC).

TSCR 97-051 &
TSCR 97-144
not shown.
Title Change

j. Deleted

k. Deleted

l. Review of every unplanned onsite release of radioactive material to the environs 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 Executive Officer and to the Safety Review Committee.

m. Deleted

AUTHORITY

6.5.1.7 The Plant Operating Review Committee shall:

a. Recommend to the Site Executive Officer approval or disapproval of items considered under 6.5.1.6(a) through (e) above.

b. Render determinations with regard to whether or not each item considered under 6.5.1.6(a) through (e) above constitutes an unreviewed safety question, as defined in 10 CFR 50.59.

c. Provide notification within 24 hours to the Chairman of the SRC and the Chief Nuclear Officer of disagreement between the PORC and the Site Executive Officer; however, the Site Executive Officer shall have responsibility for resolution of such disagreements pursuant to 6.1.1 above. LA.2

RECORDS

6.5.1.8 The Plant Operating Review Committee shall maintain minutes of each meeting and copies shall be provided to the Chairman of the SRC and the Chief Nuclear Officer.

6.5.2 SAFETY REVIEW COMMITTEE (SRC)

FUNCTION

6.5.2.1 The SRC shall function to provide independent review and audit 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

6-8

TSCR 96-101

LA.2

QUORUM

6.5.2.7 A quorum shall consist of at least a majority of the appointed individuals (or their alternates) and the Chairman (or the designated alternate). No more than two alternates may participate as SRC voting members at any one time. No more than a minority of the quorum shall have direct line responsibility for the operation of the plant.

REVIEW

6.5.2.8 The SRC 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, 10CFR, 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 of 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 plant 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 safety related structures, systems, or components.

i. Reports and meetings minutes of the Plant Operating Review Committee.

TSCR 97-051 not shown

LA.2

AUDITS

6.5.2.9 Audits of facility activities shall be performed under the cognizance of the SRC. These audits shall encompass:

a. The conformance of facility 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 facility staff at least once per 12 months.

c. The results of actions taken to correct deficiencies occurring in facility equipment, structures, systems or methods 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 50, at least once per 24 months.

e. Deleted

f. Deleted

g. Any other area of facility operation considered appropriate by the SRC or the Chief Nuclear Officer.

h. The Facility Fire Protection Program and implementing procedures at least once per two years.

i. A fire protection and loss prevention inspection and audit shall be performed annually utilizing either qualified offsite licensee personnel or an outside fire protection firm.

j. An inspection and audit of the fire protection and loss prevention program shall be performed by an outside qualified fire consultant at intervals no greater than 3 years.

k. The radiological environmental monitoring program and the results thereof at least once per 12 months.

TSCR 97-051 not shown

LA.2

l. The OFFSITE DOSE CALCULATION MANUAL and implementing procedures at least once per 24 months.

m. The PROCESS CONTROL PROGRAM and implementing procedures for processing and packaging of radioactive wastes at least once per 24 months.

AUTHORITY

6.5.2.10 The SRC shall advise the Chief Nuclear Officer on those areas of responsibility specified in Sections 6.5.2.8 and 6.5.2.9.

RECORDS

6.5.2.11 Records will be maintained in accordance with ANSI 18.7-1972. The following shall be prepared and distributed as indicated below:

a. Minutes of each SRC meeting shall be prepared and forwarded to the Chief Nuclear Officer within 30 days after the date of the meeting.

b. Reports of reviews encompassed by Section 6.5.2.8 above shall be prepared and forwarded to the Chief Nuclear Officer within 30 days following completion of the review.

c. Audit reports encompassed by Section 6.5.2.9 above, shall be forwarded to the Chief Nuclear Officer and to the management positions responsible for the areas audited within 30 days after the completion of the audit.

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

LA.3

SEE ITS 5.1

b. Each REPORTABLE EVENT shall be reviewed by the PORC and a report submitted by the Site Executive Officer to the Chief Nuclear Officer, Vice President Regulatory Affairs and Special Projects, and the Chairman of the SRC.

~~6.7~~ SAFETY LIMIT VIOLATION

Add ITS 2.2.1
Add ITS 2.2.2

M.1

SL 2.2 ~~6.7.1~~ The following actions shall be taken in the event a Safety Limit is violated:

a. The reactor shall be shut down ~~and reactor operation shall only be resumed in accordance with the provisions of 10 CFR 50.36(c)(1)(i).~~ LA.1

b. ~~The Safety Limit Violation shall be reported immediately to the Commission. The Chief Nuclear Officer, Vice President Regulatory Affairs and Special Projects, and the Chairman of the SRC will be notified within 24 hours.~~

c. ~~A Safety Limit Violation Report shall be prepared by the PORC. This report shall describe (1) applicable circumstances preceding the occurrences, (2) effects of the occurrence upon facility components, systems or structures, and (3) corrective action taken to prevent recurrence.~~ LA.1

d. ~~The Safety Limit Violation Report shall be submitted to the Commission, the Chief Nuclear Officer, the Vice President Regulatory Affairs and Special Projects, and the Chairman of the SRC by the Site Executive Officer.~~

SEE ITS 5.4 ITS 5.5.3

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, November, 1972.

b. Refueling operations.

c. Surveillance and test activities of safety related equipment.

d. Security Plan implementation.

e. Emergency Plan implementation.

f. Process Control Program implementation.

g. Offsite Dose Calculation Manual implementation.

b. ~~Each REPORTABLE EVENT shall be reviewed by the PORC and a report submitted by the Site Executive Officer to the Chief Nuclear Officer, Vice President Regulatory Affairs and Special Projects, and the Chairman of the SRC.~~

LA.2

6.7 SAFETY LIMIT VIOLATION

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

a. The reactor shall be shut down and reactor operation shall only be resumed in accordance with the provisions of 10 CFR 50.36(c)(1)(i).

SEE ITS 2.0

b. The Safety Limit Violation shall be reported immediately to the Commission. The Chief Nuclear Officer, Vice President Regulatory Affairs and Special Projects, and the Chairman of the SRC will be notified within 24 hours.

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

d. The Safety Limit Violation Report shall be submitted to the Commission, the Chief Nuclear Officer, the Vice President Regulatory Affairs and Special Projects, and the Chairman of the SRC by the Site Executive Officer.

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, November, 1972.

SEE ITS 5.4

b. Refueling operations.

c. Surveillance and test activities of safety related equipment.

d. Security Plan implementation.

e. Emergency Plan implementation.

f. Process Control Program implementation.

g. Offsite Dose Calculation Manual implementation.

TSCR 97-051 not shown

TSCR 98-018

SEE ITS 5.1

b. Each REPORTABLE EVENT shall be reviewed by the PORC and a report submitted by the Site Executive Officer to the Chief Nuclear Officer, Vice President Regulatory Affairs and Special Projects, and the Chairman of the SRC.

6.7 SAFETY LIMIT VIOLATION

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

a. The reactor shall be shut down and reactor operation shall only be resumed in accordance with the provisions of 10 CFR 50.36(c)(1)(i).

SEE ITS 2.0

b. The Safety Limit Violation shall be reported immediately to the Commission. The Chief Nuclear Officer, Vice President Regulatory Affairs and Special Projects, and the Chairman of the SRC will be notified within 24 hours.

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

d. The Safety Limit Violation Report shall be submitted to the Commission, the Chief Nuclear Officer, the Vice President Regulatory Affairs and Special Projects, and the Chairman of the SRC by the Site Executive Officer.

~~6.8~~ 5.4 PROCEDURES ~~AND PROGRAMS~~ A.1

~~6.8.1~~ 5.4.1 Written procedures shall be established, implemented and maintained covering the activities referenced below:

5.4.1a a. The applicable procedures recommended in Appendix "A" of Regulatory Guide 1.33, November, 1972.

5.4.1a b. ~~Refueling operations.~~

c. ~~Surveillance and test activities of safety related equipment.~~ A.2

d. ~~Security Plan implementation.~~

e. ~~Emergency Plan implementation.~~ LA.1

5.4.1.e f. ~~Process Control Program implementation.~~

g. ~~Offsite Dose Calculation Manual implementation.~~ A.3

Add ITS 5.4.1.e M.1

Add ITS 5.4.1 b M.2

Add ITS 5.4.1.c M.3

TSCR 97-051 Not shown. No impact

 TSCR 98-018

SEE ITS 5.1

b. Each REPORTABLE EVENT shall be reviewed by the PORC and a report submitted by the Site Executive Officer to the Chief Nuclear Officer, Vice President Regulatory Affairs and Special Projects, and the Chairman of the SRC.

~~6.7~~ SAFETY LIMIT VIOLATION

~~6.7~~.1 The following actions shall be taken in the event a Safety Limit is violated:

SEE ITS 2.0

a. The reactor shall be shut down and reactor operation shall only be resumed in accordance with the provisions of 10 CFR 50.36(c)(1)(i).

b. The Safety Limit Violation shall be reported immediately to the Commission. The Chief Nuclear Officer, Vice President Regulatory Affairs and Special Projects, and the Chairman of the SRC will be notified within 24 hours.

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

d. The Safety Limit Violation Report shall be submitted to the Commission, the Chief Nuclear Officer, the Vice President Regulatory Affairs and Special Projects, and the Chairman of the SRC by the Site Executive Officer.

~~6.8~~ 5.5.3.L PROCEDURES AND PROGRAMS

~~6.8~~.1 Written procedures shall be established, implemented and maintained covering the activities referenced below:

SEE ITS 5.4

a. The applicable procedures recommended in Appendix "A" of Regulatory Guide 1.33, November, 1972.

b. Refueling operations.

c. Surveillance and test activities of safety related equipment.

d. Security Plan implementation.

e. Emergency Plan implementation.

f. Process Control Program implementation.

g. Offsite Dose Calculation Manual implementation.

SEE ITS 5.4 and ITS 5.5.3

h. Post-accident sampling and analysis and maintenance of required equipment.

i. Collection and analysis or measurement of post-accident radioactive iodine and particulates in plant gaseous effluents and maintenance of required equipment.

j. Fire Protection Program Plan implementation.

k. Radioactive Effluent Control Program implementation.

l. Radiological Environmental Monitoring Program implementation.

6.8.2 ~~Each procedure of 6.8.1 above, and changes thereto, shall be approved prior to implementation by the appropriate responsible member(s) of management, as specified in Technical Specification 6.5.0. They shall also be reviewed periodically as set forth in administrative procedures.~~ LA.2

6.8.3 ~~Temporary changes to procedures above may be made provided:~~ LA.2

~~a. The intent of the original procedure is not altered.~~

~~b. The change is approved by two members of the plant staff, at least one of whom holds a Senior Reactor Operator's License.~~

~~c. The change is documented, and reviewed and approved by the appropriate member(s) of plant management, as specified by Technical Specification 6.5.0 within 14 days of implementation.~~

SEE ITS 5.5.4

6.8.4 The following programs shall be established, implemented, and maintained:

a. Radioactive Effluent Controls Program

A program shall be provided conforming with 10 CFR 50.36a for the control of radioactive effluents and for maintaining the doses to MEMBERS OF THE PUBLIC from radioactive effluents as low as reasonable achievable. The program (1) shall be contained in the ODCM, (2)shall be implemented by site procedures, and (3) shall include remedial actions to be taken whenever the program limits are exceeded. The program shall include the following elements:

1. Limitations on the operability of radioactive liquid and gaseous monitoring instrumentation including surveillance tests and setpoint determination in accordance with the methodology in the ODCM.

2. Limitations on the concentrations of radioactive material released in liquid effluents to UNRESTRICTED AREAS conforming to 10 times the concentration values in Appendix B, Table 2, Column 2 to 10 CFR 20.

SEE ITS 5.5.3

h. Post-accident sampling and analysis and maintenance of required equipment.

i. Collection and analysis or measurement of post-accident radioactive iodine and particulates in plant gaseous effluents and maintenance of required equipment.

5.4.1.d ~~j.~~ Fire Protection Program Plan implementation.

5.4.1.e ~~k.~~ ~~Radioactive Effluent Control Program implementation.~~

~~l.~~ ~~Radiological Environmental Monitoring Program implementation.~~ A.3

~~6.8.2~~ Each procedure of 6.8.1 above, and changes thereto, shall be approved prior to implementation by the appropriate responsible member(s) of management, as specified in Technical Specification 6.5.0. They shall also be reviewed periodically as set forth in administrative procedures.

~~6.8.3~~ Temporary changes to procedures above may be made provided:

SEE ITS 5.1

a. The intent of the original procedure is not altered.

b. The change is approved by two members of the plant staff, at least one of whom holds a Senior Reactor Operator's License.

c. The change is documented, and reviewed and approved by the appropriate member(s) of plant management, as specified by Technical Specification 6.5.0 within 14 days of implementation.

~~6.8.4~~ The following programs shall be established, implemented, and maintained:

SEE ITS 5.5.4

a. Radioactive Effluent Controls Program

A program shall be provided conforming with 10 CFR 50.36a for the control of radioactive effluents and for maintaining the doses to MEMBERS OF THE PUBLIC from radioactive effluents as low as reasonable achievable. The program (1) shall be contained in the ODCM, (2) shall be implemented by site procedures, and (3) shall include remedial actions to be taken whenever the program limits are exceeded. The program shall include the following elements:

1. Limitations on the operability of radioactive liquid and gaseous monitoring instrumentation including surveillance tests and setpoint determination in accordance with the methodology in the ODCM.

2. Limitations on the concentrations of radioactive material released in liquid effluents to UNRESTRICTED AREAS conforming to 10 times the concentration values in Appendix B, Table 2, Column 2 to 10 CFR 20.

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5.5.3.b ~~h.~~ Post-accident sampling and analysis and maintenance of required equipment.

5.5.3.b i. Collection and analysis or measurement of post-accident radioactive iodine and particulates in plant gaseous effluents and maintenance of required equipment.

SEE ITS 5.4

j. Fire Protection Program Plan implementation.

k. Radioactive Effluent Control Program implementation.

l. Radiological Environmental Monitoring Program implementation.

6.8.2 Each procedure of 6.8.1 above, and changes thereto, shall be approved prior to implementation by the appropriate responsible member(s) of management, as specified in Technical Specification 6.5.0. They shall also be reviewed periodically as set forth in administrative procedures.

SEE ITS 5.1

6.8.3 Temporary changes to procedures 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 staff, at least one of whom holds a Senior Reactor Operator's License.

c. The change is documented, and reviewed and approved by the appropriate member(s) of plant management, as specified by Technical Specification 6.5.0 within 14 days of implementation.

SEE ITS 5.5.4

6.8.4 The following programs shall be established, implemented, and maintained:

a. <u>Radioactive Effluent Controls Program</u>

A program shall be provided conforming with 10 CFR 50.36a for the control of radioactive effluents and for maintaining the doses to MEMBERS OF THE PUBLIC from radioactive effluents as low as reasonable achievable. The program (1) shall be contained in the ODCM, (2) shall be implemented by site procedures, and (3) shall include remedial actions to be taken whenever the program limits are exceeded. The program shall include the following elements:

1. Limitations on the operability of radioactive liquid and gaseous monitoring instrumentation including surveillance tests and setpoint determination in accordance with the methodology in the ODCM.

2. Limitations on the concentrations of radioactive material released in liquid effluents to UNRESTRICTED AREAS conforming to 10 times the concentration values in Appendix B, Table 2, Column 2 to 10 CFR 20.

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TSCR 97-051 not show. Title changes. No impact

SEE ITS 5.5.3

h. Post-accident sampling and analysis and maintenance of required equipment.

i. Collection and analysis or measurement of post-accident radioactive iodine and particulates in plant gaseous effluents and maintenance of required equipment.

SEE ITS 5.4

j. Fire Protection Program Plan implementation.

k. Radioactive Effluent Control Program implementation.

l. Radiological Environmental Monitoring Program implementation.

SEE ITS 5.1

~~6.8.2~~ Each procedure of 6.8.1 above, and changes thereto, shall be approved prior to implementation by the appropriate responsible member(s) of management, as specified in Technical Specification 6.5.0. They shall also be reviewed periodically as set forth in administrative procedures.

~~6.8.3~~ Temporary changes to procedures 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 staff, at least one of whom holds a Senior Reactor Operator's License.

c. The change is documented, and reviewed and approved by the appropriate member(s) of plant management, as specified by Technical Specification 6.5.0 within 14 days of implementation.

~~6.8.4~~ 5.5.4 The following programs shall be established, implemented, and maintained:

a. Radioactive Effluent Controls Program

A program shall be provided conforming with 10 CFR 50.36a for the control of radioactive effluents and for maintaining the doses to MEMBERS OF THE PUBLIC from radioactive effluents as low as reasonable achievable. The program (1) shall be contained in the ODCM, (2) shall be implemented by site procedures, and (3) shall include remedial actions to be taken whenever the program limits are exceeded. The program shall include the following elements:

functional capability A.2

5.5.4.a ~~1.~~ Limitations on the operability of radioactive liquid and gaseous monitoring instrumentation including surveillance tests and setpoint determination in accordance with the methodology in the ODCM.

5.5.4.b ~~2.~~ Limitations on the concentrations of radioactive material released in liquid effluents to UNRESTRICTED AREAS conforming to 10 times the concentration values in Appendix B, Table 2, Column 2 to 10 CFR 20.

5.5.4.c ~~3.~~ Monitoring, sampling, and analysis of radioactive liquid and gaseous effluents pursuant to 10 CFR 20.1302 (except as discussed in 6.8.4.a.2) and with the methodology and parameters in the ODCM.

5.5.4.d ~~4.~~ Limitations on the annual and quarterly doses or dose commitment to a MEMBER OF THE PUBLIC from radioactive materials in liquid effluents released from each unit to UNRESTRICTED AREAS conforming to Appendix I to 10 CFR Part 50.

5.5.4.e ~~5.~~ Determinations of cumulative and projected dose contributions from radioactive effluents for the current calendar quarter and current calendar year in accordance with the methodology and parameters in the ODCM at least every 31 days.

functional capability — A.2

5.5.4.f ~~6.~~ Limitations on the ~~operability~~ and use of the liquid and gaseous effluent treatment systems to ensure that the appropriate portions of these systems are used to reduce releases of radioactivity when the projected doses in a 31 day period would exceed 2 percent of the guidelines for the annual dose or dose commitment conforming to Appendix I to 10 CFR Part 50.

5.5.4.g ~~7.~~ Limitations on the dose rate resulting from radioactive material released in gaseous effluents from the site to areas at or beyond the SITE BOUNDARY shall be limited to the following:

1 ~~a.~~ For noble gases: Less than or equal to a dose rate of 500 mrems/yr to the total body and less than or equal to a dose rate of 3000 mrems/yr to the skin, and

2 ~~b.~~ For iodine-131, tritium, and for all radionuclides in particulate form with half-lives greater than 8 days: Less than or equal to dose rate of 1500 mrems/yr to any organ.

5.5.4.h ~~8.~~ Limitations on the annual and quarterly air doses resulting from noble gases released in gaseous effluents from each unit to areas beyond the SITE BOUNDARY conforming to Appendix I to 10 CFR Part 50.

5.5.4.i 9. Limitations on the annual and quarterly doses to a MEMBER OF THE PUBLIC from iodine-131, tritium, and all radionuclides in particulate form with half-lives greater than 8 days in gaseous effluents released from each unit to areas beyond the SITE BOUNDARY conforming to Appendix I to 10 CFR Part 50.

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

LA.2

b. Radiological Environmental Monitoring Program

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

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

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

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

SEE ITS 5.5.4

c. Process Control Program

A program shall be provided to ensure that the processing and packaging of solid radioactive wastes shall be accomplished in compliance with 10 CFR Parts 20, 61 and 71, and Federal and State regulations and other requirements governing the disposal of solid radioactive waste. The program requirements shall be contained in the PCP manual.

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b. Radiological Environmental Monitoring Program

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

SEE ITS 5.5.1

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

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

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

c. ~~Process Control Program~~

~~A program shall be provided to ensure that the processing and packaging of solid radioactive wastes shall be accomplished in compliance with 10 CFR Parts 20, 61 and 71, and Federal and State regulations and other requirements governing the disposal of solid radioactive waste. The program requirements shall be contained in the PCP manual.~~ LA.1

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6.9 REPORTING REQUIREMENTS

ROUTINE REPORTS

5.6 ~~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 - Region 1, unless otherwise noted.~~ A8 LA.1

STARTUP REPORT

6.9.1.1 ~~A summary report of appropriate plant testing shall be submitted following (1), an amendment to the license involving a planned increase in power level, (2) installation of fuel that has a different design and (3) modifications that may have significantly altered the nuclear, thermal, or hydraulic performances of the plant. The report shall address each of the tests identified in the FSAR and shall in general include a description of the measured values of the operating conditions or characteristics obtained during the testing and comparison of these values with acceptance criteria. 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.~~

LA.1

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6.9.1.2 ~~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 program, and resumption or commencement of commercial power operation), supplementary reports shall be submitted at least every three months until all three events have been completed.~~ LA.1

5.6.1 Occupational ~~ANNUAL~~ RADIATION EXPOSURE REPORTS A.2

6.9.1.3 A tabulation on an annual basis of the number of station, utility and other personnel (including contractors), for whom monitoring was ~~required~~ performed receiving deep dose exposures greater than 100 mrem/yr and their associated man-rem exposures according to work and job functions, 1/ e.g., reactor operations and surveillance, inservice inspection, routine maintenance, special maintenance, waste processing, and refueling. The dose assignment to various duty functions may be estimates based on pocket dosimeter, TLD, electronic dosimeter or 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. due April 30 A.4 A.3

MONTHLY OPERATING REPORT

~~6.9.1.4~~ 5.6.4 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 Region 1,~~ no later than the 15th of each month following the calendar month covered by the report. A.8

ANNUAL REPORTS

6.9.1.5 ~~A report of specific activity analysis results in which the primary coolant exceeded the limits of Specification 3.1.D. The following information shall be included: (1) Reactor power history starting 48 hours prior to the first sample in which the limit was exceeded; (2) Results of the last isotopic analysis for radioiodine performed prior to exceeding the limit, results of analysis while activity was reduced to less than limit. Each result should include date and time of sampling and the radioiodine concentrations; (3) Clean-up system flow history starting 48 hours prior to the first sample in which the limit was exceeded; (4) Data providing the I-131 concentration and one other radioiodine isotope concentration in microcuries per gram as a function of time for the duration of the specific activity above the steady-state level; and (5) The time duration when the specific activity of the primary coolant exceeded the radioiodine limit.~~ L.1

5.6.1 1/ This tabulation supplements the requirements of 20.2206 of 10 CFR Part 20

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5.6.5 ~~6.9.1.6~~ CORE OPERATING LIMITS REPORT

5.6.5a 6.9.1.6.a Core operating limits shall be established and documented in the CORE OPERATING LIMITS REPORT before each reload cycle or any remaining part of a reload cycle for the following: 3.2.3

1. Axial Flux Difference limits for Specification 3.10.2.

2. Heat Flux Hot Channel Factor and K(Z) for Specification ~~3.10.2~~. 3.2.1

3. Nuclear Enthalpy Rise Hot Channel Factor and Power Factor Multiplier for Specification ~~3.10.2~~ 3.2.2

4. Shutdown Bank Insertion Limit for Specification ~~3.10.4~~. 3.1.5

5. Control Bank Insertion Limits for Specification ~~3.10.4~~. 3.1.6

5.6.5b ~~6.9.1.6.b~~ The analytical methods used to determine the core operating limits shall be those previously reviewed and approved by NRC in:

1. WCAP-9272-P-A, "WESTINGHOUSE RELOAD SAFETY EVALUATION METHODOLOGY," July 1985 (W Proprietary). (Methodology for Specification ~~3.10.4~~ 3.1.5 and 3.1.6 - Shutdown Bank Insertion Limit, Control Bank Insertion Limits and ~~3.10.2~~ 3.2.2 - Nuclear Enthalpy Rise Hot Channel Factor.)

2a. WCAP-8385, "POWER DISTRIBUTION CONTROL AND LOAD FOLLOWING PROCEDURES - TOPICAL REPORT," September 1974 (W Proprietary). (Methodology for Specification ~~3.10.2~~ 3.2.3 - Axial Flux Difference (Constant Axial Offset Control).)

2b. T. M. Anderson to K. Kneil (Chief of Core Performance Branch, NRC) January 31, 1980 -- Attachment: Operation and Safety Analysis Aspects of an Improved Load Follow Package.
(Methodology for Specification 3.10.2 - 3.2.3
Axial Flux Difference (Constant Axial Offset Control).)

2c. NUREG-0800, Standard Review Plan, U.S. Nuclear Regulatory Commission, Section 4.3, Nuclear Design, July 1981. Branch Technical Position CPB 4.3-1, Westinghouse Constant Axial Offset Control (CAOC), Rev. 2, July 1981.
(Methodology for Specification 3.10.2 - 3.2.3
Axial Flux Difference (Constant Axial Offset Control).)

3a. WCAP-9220-P-A, Rev. 1, "WESTINGHOUSE ECCS EVALUATION MODEL-1981 VERSION," February 1982 (W Proprietary).
(Methodology for Specification 3.10.2 - 3.2.1
Heat Flux Hot Channel Factor.)

3b. WCAP-9561-P-A ADD. 3, Rev. 1, "BART A-1: A COMPUTER CODE FOR THE BEST ESTIMATE ANALYSIS OF REFLOOD TRANSIENTS - SPECIAL REPORT: THIMBLE MODELING W ECCS EVALUATION MODEL," July 1986 (W Proprietary).
(Methodology for Specification 3.10.2 - 3.2.1
Heat Flux Hot Channel Factor.)

3c. WCAP-10266-P-A Rev. 2, "THE 1981 VERSION OF WESTINGHOUSE EVALUATION MODEL USING BASH CODE," March 1987, (W Proprietary).
(Methodology for Specification 3.10.2 - 3.2.1
Heat Flux Hot Channel Factor.)

3d. WCAP-10054-P-A, "SMALL BREAK ECCS EVALUATION MODEL USING NOTRUMP CODE," (W Proprietary).
(Methodology for Specification 3.10.2 - 3.2.1
Heat Flux Hot Channel Factor).

3e. WCAP-10079-P-A, "NOTRUMP NODAL TRANSIENT SMALL BREAK AND GENERAL NETWORK CODE," (W Proprietary).
(Methodology for Specification 3.10.2 - 3.2.1
Heat Flux Hot Channel Factor).

3f. WCAP-12610, "VANTAGE+ Fuel Assembly Report," (W Proprietary).
(Methodology for Specification 3.10.2 - Heat Flux Hot Channel Factor). 3.2.3

~~6.9.1.6.c~~ 5.6.5.c The core operating limits shall be determined so that all applicable limits (e.g., fuel thermal-mechanical limits, core thermal-hydraulic limits, ECCS limits, nuclear limits such as shutdown margin, and transient and accident analysis limits) of the safety limits are met.

~~6.9.1.6.d~~ 5.6.5.d The CORE OPERATING LIMITS REPORT, including any mid-cycle revisions or supplements thereto, shall be provided upon issuance, for each reload cycle, ~~to the NRC Document Control Desk with copies to the Regional Administrator and Resident Inspector~~. A.8

SPECIAL REPORTS

~~6.9.2~~ 5.6 Special reports shall be submitted ~~to the Regional Administrator Region 1 within the time period specified for each report~~. These reports shall be submitted covering the activities identified below pursuant to the requirements of the applicable reference specification; A.8

SEE RELOCATED CTS

a. Sealed source leakage on excess of limits (Specification 3.9)

b. Inoperable Seismic Monitoring Instrumentation (Specification 4.10)

c. Seismic event analysis (Specification 4.10)

5.6.7 d. ~~Inoperable plant vent sampling, main steam line radiation monitoring or effluent monitoring capability (Table 3.5-4, items 5, 6 and 7)~~ A.12

5.6.8 e. The complete results of the steam generator tube inservice inspection ~~(Specification 4.9.C)~~

~~f. Deleted~~.

SEE RELOCATED

g. Release of radioactive effluents in excess of limits (Technical Specification 6.8.4.a)

Add ITS 5.6.7, PAM Instrumentation — A.9

Add ITS 5.6.6, PTLR — M.1

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3f. WCAP-12610, "VANTAGE+ Fuel Assembly Report," (W Proprietary).
(Methodology for Specification 3.10.2 - Heat Flux Hot Channel Factor).

SEE ITS 5.6

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

6.9.1.6.d The CORE OPERATING LIMITS REPORT, including any mid-cycle revisions or supplements thereto, shall be provided upon issuance, for each reload cycle, to the NRC Document Control Desk with copies to the Regional Administrator and Resident Inspector.

SPECIAL REPORTS

~~6.9.2 Special reports shall be submitted to the Regional Administrator-Region 1 within the time period specified for each report. These reports shall be submitted covering the activities identified below pursuant to the requirements of the applicable reference specification;~~

R.14

a. ~~Sealed source leakage on excess of limits (Specification 3.9)~~

SEE CTS MASTER MARKUP

b. Inoperable Seismic Monitoring Instrumentation (Specification 4.10)

c. Seismic event analysis (Specification 4.10)

d. Inoperable plant vent sampling, main steam line radiation monitoring or effluent monitoring capability (Table 3.5-4, items 5, 6 and 7)

e. The complete results of the steam generator tube inservice inspection (Specification 4.9.C)

f. Deleted

g. Release of radioactive effluents in excess of limits ~~(Appendix B Specifications 2.3, 2.4, 2.5, 2.6)~~ TSCR 98-018

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SEE ITS 5.6

3f. WCAP-12610, "VANTAGE+ Fuel Assembly Report," (W Proprietary).
(Methodology for Specification 3.10.2 - Heat Flux Hot Channel Factor).

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

6.9.1.6.d The CORE OPERATING LIMITS REPORT, including any mid-cycle revisions or supplements thereto, shall be provided upon issuance, for each reload cycle, to the NRC Document Control Desk with copies to the Regional Administrator and Resident Inspector.

SPECIAL REPORTS

~~6.9.2 Special reports shall be submitted to the Regional Administrator-Region 1 within the time period specified for each report. These reports shall be submitted covering the activities identified below pursuant to the requirements of the applicable reference specification;~~ R.20

SEE R.14

a. Sealed source leakage on excess of limits (Specification 3.9)

R.20

~~b. Inoperable Seismic Monitoring Instrumentation (Specification 4.10)~~

~~c. Seismic event analysis (Specification 4.10)~~ R.20

SEE ITS 5.6

d. Inoperable plant vent sampling, main steam line radiation monitoring or effluent monitoring capability (Table 3.5-4, items 5, 6 and 7)

e. The complete results of the steam generator tube inservice inspection (Specification 4.9.C)

f. Deleted

g. Release of radioactive effluents in excess of limits ~~(Appendix B Specifications 2.3, 2.4, 2.5, 2.6)~~ TSCR 98-018

TSCR 98-018

5.6.7	h.	Inoperable containment high-range radiation monitors (Table 3.5-5, Item 24)	A.12
SEE RELOCATED	i.	Radioactive environmental sampling results in excess of reporting levels (Technical Specification 6.8.4.b)	
5.6.4	j.	Operation of Overpressure Protection System (Specification 3.1.A.8.c)	
SEE RELOCATED	k.	Operation of Toxic Gas Monitoring Systems (Specification 3.3.H.3.)	
5.5.11	l.	Inoperable explosive gas monitoring instrumentation (Appendix B, Technical Specification 1.1.1)	

6.10 RECORD RETENTION

6.10.1 The following records shall be retained for at least five years:

a. Records and logs of facility operation covering time interval at each power level.

b. Records and logs of principal maintenance activities, inspection, repair and replacements of principal items of equipment related to nuclear safety.

c. ALL REPORTABLE EVENTS submitted to the Commission.

d. Records of surveillance activities, inspections and calibrations required by these Technical Specifications.

e. Records of changes made to Operating Procedures.

f. Records of radioactive shipments.

g. Records of sealed source and fission detector leak tests and results.

h. Records of annual physical inventory of all source material of record.

i. Records of reactor tests and experiments.

6.10.2 The following records shall be retained for the duration of the Facility Operating License:

a. Records of any drawing changes reflecting facility design modifications made to systems and equipment described in the Final Safety Analysis Report.

LA.2

h. Inoperable containment high-range radiation monitors (Table 3.5-5, Item 24)

i. Radioactive environmental sampling results in excess of reporting levels (~~Appendix B Specification 2.7, 2.8, 2.9~~ Technical Specification 6.8.4.b)

j. Operation of Overpressure Protection System (Specification 3.1.A.8.c)

R.18 k. Operation of Toxic Gas Monitoring Systems (Specification 3.3.H.3.) R.18

~~l. Inoperable explosive gas monitoring instrumentation (Appendix B, Technical Specification 1.1.1)~~

6.10 RECORD RETENTION

6.10.1 The following records shall be retained for at least five years:

a. Records and logs of facility operation covering time interval at each power level.

b. Records and logs of principal maintenance activities, inspection, repair and replacements of principal items of equipment related to nuclear safety.

c. ALL REPORTABLE EVENTS submitted to the Commission.

d. Records of surveillance activities, inspections and calibrations required by these Technical Specifications.

e. Records of changes made to Operating Procedures.

f. Records of radioactive shipments.

g. Records of sealed source and fission detector leak tests and results.

h. Records of annual physical inventory of all source material of record.

i. Records of reactor tests and experiments.

SEE CTS MASTER MARKUP

6.10.2 The following records shall be retained for the duration of the Facility Operating License:

a. Records of any drawing changes reflecting facility 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 facility radiation and contamination surveys.

d. Records of radiation exposure for all individuals entering radiation control areas.

e. Records of gaseous and liquid radioactive material released to the environs.

f. Records of transient or operational cycles for those facility components designed for a limited number of transient cycles.

g. Records of training and qualifications for current members of the plant staff.

h. Records of in-service inspections performed pursuant to these Technical Specifications.

i. Records of Quality Assurance activities required by the QA 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 the SRC.

l. Records for Environmental Qualification which are covered under the provisions of paragraph 6.13.

m. Records of secondary water sampling and water quality.

n. 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 records showing that these procedures were followed.

o. Records of service lives of all safety-related hydraulic snubbers including the date at which the service life commences and associated installation and maintenance records.

p. Records of reviews performed for changes made to the OFFSITE DOSE CALCULATION MANUAL and the PROCESS CONTROL PROGRAM.

LA.2

~~6.11~~ ~~RADIATION AND RESPIRATORY PROTECTION PROGRAM~~

~~6.11.1~~ ~~Procedures for personnel radiation protection shall be prepared consistent with the requirements of 10 CFR 20 and shall be approved, maintained and adhered to for all operations involving personnel radiation exposure so as to maintain exposures as far below the limits specified in 10 CFR 20 as reasonably achievable. Pursuant to 10 CFR 20.1703, allowance may be made for the use of respiratory protection equipment in conjunction with activities authorized by the operating license for this plant in determining whether individuals in restricted areas are exposed to concentrations in excess of the limits specified in Appendix B, Table 1, Column 3 of 10 CFR 20.~~ LA.1

~~6.12~~ 5.7 HIGH RADIATION AREA

~~6.12.1~~ 5.7.1 In lieu of the "control device" or "alarm signal" required by paragraph 20.1601 of 10 CFR 20, each high radiation area in which the intensity of radiation is greater than 100 mrem/hr** but less than 1000 mrem/hr** 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)*. Any individual or group of individuals permitted to enter such areas shall be provided or accompanied by one or more of the following:

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

5.7.1.b 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 level in the area has been established and personnel have been made knowledgeable of them.

5.7.1.c c. An individual qualified in radiation protection procedures who is equipped with a radiation dose rate monitoring device. This individual shall be responsible for providing positive control over the activities within the area and shall perform periodic radiation surveillance at the frequency specified by the facility ~~Health Physicist~~ radiation protection manager in the Radiation Work Permit. A.2

5.7.1 * Health Physics Personnel* shall be exempt from the RWP issuance requirements for entries into high radiation areas with exposure rates ≤ 1000 mrem/hr, or personnel continuously escorted by such personnel during the performances of their assigned radiation protection duties, provided they comply with approved radiation protection procedures for entry into high radiation areas. L.1

** Measured at 30 centimeters (12 inches) from the source of radioactivity. LA.2

6.12.2 The requirements of 6.12.1 above, shall also apply to each high radiation area in which the intensity of radiation is greater than 1000 mrem/hr. In addition, locked doors shall be provided to prevent unauthorized entry into such areas and the keys shall be maintained under the administrative control of the Shift Manager on duty and/or the plant Radiological and Environmental Services Manager or his designee.

6.13 ENVIRONMENTAL QUALIFICATION

6.13.1 Environmental qualification of electric equipment important to safety shall be in accordance with the provisions of 10 CFR 50.49. Pursuant to 10 CFR 50.49, Section 50.49 (d), the EQ Master List identifies electrical equipment requiring environmental qualification.

6.13.2 Complete and auditable records which describe the environmental qualification method used, for all electrical equipment identified in the EQ Master List, in sufficient detail to document the degree of compliance with the appropriate requirements of 10 CFR 50.49 shall be available and maintained at a central location. Such records shall be updated and maintained current as equipment is replaced, further tested, or otherwise further qualified.

6.14 CONTAINMENT LEAKAGE RATE TESTING PROGRAM

A program shall be established to implement the leakage rate testing of the containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B, as modified by approved exemptions. This program shall be in accordance with the guidelines contained in Regulatory Guide 1.163, "Performance-Based Containment Leak Test Program, dated September 1995" as modified by the following exception:

a. ANS 56.8 - 1994, Section 3.3.1: WCCPPS isolation valves are not Type C tested.

The maximum allowable primary containment leakage rate, L_a at a minimum test pressure equal to P_a, shall be 0.1% of primary containment air weight per day. P_a is the peak calculated containment internal pressure related to the design basis accident.

Leakage acceptance criteria are:

a. Containment leakage rate acceptance criterion is $\leq 1.0\ L_a$. During the first unit startup following testing in accordance with this program, the leakage rate acceptance criteria are $\leq 0.60\ L_a$ for the Type B and C tests and $\leq 0.75 L_a$ for Type A tests;

b. Air lock testing acceptance criteria are :

1) Overall air lock leakage rate is $\leq 0.05\ L_a$ when tested at $\geq P_a$,

2) For each door, leakage rate is $\leq 0.01\ L_a$ when pressurized to $\geq P_a$.

c. Isolation valves sealed with the service water system leakage rate into containment acceptance criterion is ≤ 0.36 gpm per fan cooler unit

TSCR 98-043

~~6.12.2*~~ 5.7.2 In addition to the requirements of 6.12.1 above, areas accessible to individuals with radiation levels such that an individual could receive in 1 hour a dose greater than 1000 mrem**, shall be provided with locked doors to prevent unauthorized entry, and the keys shall be maintained under the administrative control of the Shift Supervisor on duty and/or the plant Radiological and Environmental Services Manager or his designee. health physics supervisor — A

SEE ITS 5.4

6.13 ENVIRONMENTAL QUALIFICATION

6.13.1 Environmental qualification of electric equipment important to safety shall be in accordance with the provisions of 10 CFR 50.49. Pursuant to 10 CFR 50.49, Section 50.49 (d), the EQ Master List identifies electrical equipment requiring environmental qualification.

6.13.2 Complete and auditable records which describe the environmental qualification method used, for all electrical equipment identified in the EQ Master List, in sufficient detail to document the degree of compliance with the appropriate requirements of 10 CFR 50.49 shall be available and maintained at a central location. Such records shall be updated and maintained current as equipment is replaced, further tested, or otherwise further qualified.

SEE ITS 5.5.15

6.14 CONTAINMENT LEAKAGE RATE TESTING PROGRAM

A program shall be established to implement the leakage rate testing of the containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B, as modified by approved exemptions. This program shall be in accordance with the guidelines contained in Regulatory Guide 1.163, "Performance-Based Containment Leak Test Program, Dated September 1995" as modified by the following exception:

a. ANS 56.8 - 1994, Section 3.3.1: WCCPPS isolation valves are not Type C tested.

The peak calculated primary containment internal pressure for the design basis loss of coolant accident, P_a, is 42.39 psig. The minimum test pressure is 42.42 psig.

The maximum allowable primary containment leakage rate, L_a, at P_a, shall be 0.1% of primary containment air weight per day.

Leakage acceptance criteria are:

a. Containment leakage rate acceptance criterion is $\leq 1.0\ L_a$. During the first unit startup following testing in accordance with this program, the leakage rate acceptance criteria are $\leq 0.60\ L_a$ for the Type B and C tests and $\leq 0.75\ L_a$ for Type A tests;

b. Air lock acceptance criteria are:

   1) Overall the air lock leakage rate is $\leq 0.05\ L_a$ when tested at $\geq P_a$,

   2) For each door, leakage rate is $\leq 0.01\ L_a$ when pressurized to $\geq P_a$.

c. Isolation valves sealed with the service water system leakage rate into containment acceptance criterion is ≤ 0.36 gpm per fan cooler unit

5.7.1 * Health Physics Personnel shall be exempt from the RWP issuance requirements for entries into high radiation areas during the performances of their assigned radiation protection duties, provided they comply with approved radiation protection procedures for entry into high radiation areas.

** ~~Measured at 30 centimeters (12 inches) from the source of radioactivity~~ — LA.2

See page CTS 6-21

TSCR 98-018

Relocated Item (R-13)

SEE ITS 5.7

6.12.2* In addition to the requirements of 6.12.1 above, areas accessible to individuals with radiation levels such that an individual could receive in 1 hour a dose greater than 1000 mrem**, shall be provided with locked doors to prevent unauthorized entry, and the keys shall be maintained under the administrative control of the Shift Supervisor on duty and/or the plant Radiological and Environmental Services Manager or his designee.

SEE ITS 5.4

6.13 ENVIRONMENTAL QUALIFICATION

6.13.1 Environmental qualification of electric equipment important to safety shall be in accordance with the provisions of 10 CFR 50.49. Pursuant to 10 CFR 50.49, Section 50.49 (d), the EQ Master List identifies electrical equipment requiring environmental qualification.

6.13.2 Complete and auditable records which describe the environmental qualification method used, for all electrical equipment identified in the EQ Master List, in sufficient detail to document the degree of compliance with the appropriate requirements of 10 CFR 50.49 shall be available and maintained at a central location. Such records shall be updated and maintained current as equipment is replaced, further tested, or otherwise further qualified.

SEE ITS 5.5.15

~~6.14~~ CONTAINMENT LEAKAGE RATE TESTING PROGRAM

A program shall be established to implement the leakage rate testing of the containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B, as modified by approved exemptions. This program shall be in accordance with the guidelines contained in Regulatory Guide 1.163, "Performance-Based Containment Leak Test Program, Dated September 1995" as modified by the following exception:

a. ANS 56.8 - 1994, Section 3.3.1: WCCPPS isolation valves are not Type C tested.

The peak calculated primary containment internal pressure for the design basis loss of coolant accident, P_a, is 42.39 psig. The minimum test pressure is 42.42 psig.

The maximum allowable primary containment leakage rate, L_a, at P_a, shall be 0.1% of primary containment air weight per day.

See TSCR 98-043 Next Page.

Leakage acceptance criteria are:

a. Containment leakage rate acceptance criterion is $\leq 1.0\ L_a$. During the first unit startup following testing in accordance with this program, the leakage rate acceptance criteria are $\leq 0.60\ L_a$ for the Type B and C tests and $\leq 0.75\ L_a$ for Type A tests;

b. Air lock acceptance criteria are:

1) Overall the air lock leakage rate is $\leq 0.05\ L_a$ when tested at $\geq P_a$,

2) For each door, leakage rate is $\leq 0.01\ L_a$ when pressurized to $\geq P_a$.

R-13

c. ~~Isolation valves sealed with the service water system leakage rate into containment acceptance criterion is ≤0.36 gpm per fan cooler unit~~ (R-13)

SEE ITS 5.7

* Health Physics Personnel shall be exempt from the RWP issuance requirements for entries into high radiation areas during the performances of their assigned radiation protection duties, provided they comply with approved radiation protection procedures for entry into high radiation areas.

** Measured at 30 centimeters (12 inches) from the source of radioactivity.

TSCR 98-018

Amendment No. 11, 55 (Order dated October 24, 1980), 88, 101, 103, 116, 117, 162, 174

See Also TSCR 98-043

SEE ITS 5.7

6.12.2* In addition to the requirements of 6.12.1 above, areas accessible to individuals with radiation levels such that an individual could receive in 1 hour a dose greater than 1000 mrem**, shall be provided with locked doors to prevent unauthorized entry, and the keys shall be maintained under the administrative control of the Shift Supervisor on duty and/or the plant Radiological and Environmental Services Manager or his designee.

SEE ITS 5.4

6.13 ENVIRONMENTAL QUALIFICATION

6.13.1 Environmental qualification of electric equipment important to safety shall be in accordance with the provisions of 10 CFR 50.49. Pursuant to 10 CFR 50.49, Section 50.49 (d), the EQ Master List identifies electrical equipment requiring environmental qualification.

6.13.2 Complete and auditable records which describe the environmental qualification method used, for all electrical equipment identified in the EQ Master List, in sufficient detail to document the degree of compliance with the appropriate requirements of 10 CFR 50.49 shall be available and maintained at a central location. Such records shall be updated and maintained current as equipment is replaced, further tested, or otherwise further qualified.

5.5.15 ~~6.14~~ CONTAINMENT LEAKAGE RATE TESTING PROGRAM

A program shall be established to implement the leakage rate testing of the containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B, as modified by approved exemptions. This program shall be in accordance with the guidelines contained in Regulatory Guide 1.163, "Performance-Based Containment Leak Test Program, Dated September 1995" as modified by the following exception:

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The maximum allowable primary containment leakage rate, L_a, at P_a, shall be 0.1% of primary containment air weight per day.

See TSCR 98-043 Next Page

Leakage acceptance criteria are:

a. Containment leakage rate acceptance criterion is $\leq 1.0\ L_a$. During the first unit startup following testing in accordance with this program, the leakage rate acceptance criteria are $\leq 0.60\ L_a$ for the Type B and C tests and $\leq 0.75\ L_a$ for Type A tests;

b. Air lock acceptance criteria are:

1) Overall the air lock leakage rate is $\leq 0.05\ L_a$ when tested at $\geq P_a$,

2) For each door, leakage rate is $\leq 0.01\ L_a$ when pressurized to $\geq P_a$.

SEE RELOCATED

c. Isolation valves sealed with the service water system leakage rate into containment acceptance criterion is ≤ 0.36 gpm per fan cooler unit

SEE ITS 5.7

* Health Physics Personnel shall be exempt from the RWP issuance requirements for entries into high radiation areas during the performances of their assigned radiation protection duties, provided they comply with approved radiation protection procedures for entry into high radiation areas.

** Measured at 30 centimeters (12 inches) from the source of radioactivity.

TSCR 98-018

Amendment No. ~~11~~, ~~59~~ (Order dated October 24, 1980), ~~88~~, ~~101~~, ~~103~~, ~~116~~, ~~117~~, ~~162~~, ~~174~~

See Also TSCR 98-043

c ~~d~~. Isolation Valve Seal Water System leakage rate acceptance criterion is 14,700 cc/hr at $1.1P_a$.

~~The provisions of Specification 1.12 do not apply to the test frequencies specified in the Primary Containment Leakage Rate Testing Program. The provisions of Specification 4.1, "Applicability," as they relate to delay of 24 hours in applying an LCO following the discovery of a surveillance test not performed, are applicable to the Primary Containment Leakage Rate Testing Program.~~

SR 3.0.2 is not applicable. A3

SR 3.0.3 is applicable. A4

1/2.0 LIMITING CONDITIONS FOR OPERATION AND SURVEILLANCE REQUIREMENTS

~~1/2.1 MONITORING INSTRUMENTATION~~

~~1.1.1 EXPLOSIVE GAS MONITORING INSTRUMENTATION~~

~~LCO:~~

~~The explosive gas monitoring instrumentation channels shown in Table 1.1.1-1 shall be OPERABLE with their alarm/trip setpoints set to ensure that the limits of Appendix B Technical Specification 1.3.1 are not exceeded.~~

~~APPLICABILITY: As shown in Table 1.1.1-1.~~

~~ACTION:~~

~~A. With an explosive gas monitoring instrumentation channel alarm/trip setpoint less conservative than required by the above Specification, declare the channel inoperable and take the ACTION shown in Table 1.1.1-1.~~

~~B. With less than the minimum number of explosive gas monitoring instrumentation channels OPERABLE, take the ACTION shown in Table 1.1.1-1. Exert best efforts to return the instruments to OPERABLE status within 30 days and, if unsuccessful, prepare and submit to the Commission, pursuant to Appendix B Technical Specification 4.3.1, a Special Report to explain why the inoperability was not corrected within this time frame.~~

~~2.1.1 SURVEILLANCE REQUIREMENTS~~

~~The explosive gas monitoring instrumentation channels shall be demonstrated OPERABLE by performance of the CHANNEL CHECK and CHANNEL CALIBRATION operations at the frequencies shown in Table 2.1.1-1.~~

LA.4

Amendment No. 81,

TSCR 98-018

TABLE 1.1.1-1

EXPLOSIVE GAS MONITORING INSTRUMENTATION			
INSTRUMENT	MINIMUM CHANNELS OPERABLE	APPLICABILITY	ACTION
1. WASTE GAS HOLDUP SYSTEM EXPLOSIVE GAS MONITORING SYSTEM			
a. Hydrogen Monitor	(1)	*	1
b. Oxygen Monitor	(1)	*	1

TABLE NOTATION

* During waste gas holdup system operation (treatment for primary system offgases).

ACTION 1 - With the number of channels OPERABLE one less than required by the Minimum Channels OPERABLE requirement, operation of this system may continue provided grab samples of waste tank on reuse or receipt are taken and analyzed daily. With both channels inoperable operation may continue provided grab samples of waste tank on reuse or receipt are taken and analyzed as follows:

a) Every 4 hours during degassing operations,

b) Daily during other operations.

LA.4

ETS 1/2-2

TABLE 2.1.1-1

EXPLOSIVE GAS MONITORING INSTRUMENTATION SURVEILLANCE REQUIREMENTS			
INSTRUMENT	CHANNEL CHECK	CHANNEL CALIBRATION	MODES IN WHICH SURVEILLANCE REQUIRED
1. WASTE GAS HOLDUP SYSTEM EXPLOSIVE GAS MONITORING SYSTEM			
a. Hydrogen Monitor	D	M(1)	*
b. Oxygen Monitor	D	M(2)	*

TABLE NOTATION

* During waste gas holdup system operation (treatment for primary system off gases).

(1) The CHANNEL CALIBRATION shall include the use of standard gas samples containing:

1. Less than or equal to two volume percent hydrogen,

and

2. Greater than or equal to four volume percent hydrogen,

(2) The CHANNEL CALIBRATION shall include the use of standard gas samples containing:

1. Less than or equal to one volume percent oxygen,

and

2. Greater than or equal to four volume percent oxygen.

D Daily
M Monthly

LA4

A 1

1/2.2 RADIOACTIVE LIQUID EFFLUENTS

1.2.1 RADIOACTIVE LIQUID EFFLUENT HOLDUP TANKS*

~~LCO:~~ A surveillance program to ensure — A.

5.5.11.c The quantity of radioactive material contained in each of the following unprotected outdoor tanks shall be limited to less than or equal to 10 curies, excluding tritium and dissolved or entrained noble gases.

a. Refueling Water Storage Tank**
b Primary Water Storage Tank
c. 31 Monitor Tank
d. 32 Monitor Tank
e. Outside Temporary Tank***

APPLICABILITY: At all times.

ACTION:

With the quantity of radioactive material in any of the above listed tanks exceeding the above limit, immediately suspend all additions of radioactive material to the tank. Within 48 hours reduce the tank contents to within the limit, and describe the events leading to this condition in the next Annual Radioactive Effluent Release Report.

LA.1

2.2.1 SURVEILLANCE REQUIREMENTS

The quantity of radioactive material contained in each of the listed tanks shall be determined to be less than or equal to 10 curies excluding tritium and dissolved or entrained noble gases, by analyzing a representative sample of the tank's contents at least once per month when radioactive materials are being added to the tank.

5.5.11.c * Tanks included in this specification are those outdoor tanks that are not surrounded by liners, dikes, or walls capable of holding the tank contents and that do not have tank overflows and surrounding area drains connected to the liquid radwaste treatment system.

** After refueling operations, liquid from the reactor cavity will be sampled for radioactive material content prior to being pumped into the tank.

*** Liquid will be sampled for radioactive content prior to being pumped into the tank.

LA.1

SR 3.0.2 and SR 3.0.3 are applicable — A.2 A.3

Amendment No. 51, TSCR 98-018

1/2.3 RADIOACTIVE GASEOUS EFFLUENTS

~~1.3.1~~ EXPLOSIVE GAS MIXTURE (Hydrogen rich systems not designed to withstand a hydrogen explosion)

LCO: within limits and verified periodically LA.2

5.5.11.a 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 2% by volume, immediately suspend all additions of waste gases to this portion of the system and reduce the concentration of oxygen to less than or equal to 2% by volume.

LA.2

5.5.11a ~~2.3.1~~ SURVEILLANCE REQUIREMENTS

The concentrations of hydrogen and oxygen in the waste gas holdup system shall be determined to be within the above limits by monitoring the waste gases in the waste gas holdup system with the hydrogen and oxygen monitors required OPERABLE by Appendix B Technical Specification Table 1.1.1-1.

LA.2

1.3.2 GAS STORAGE TANKS

~~LCO:~~ {a surveillance program to ensure} A.

The quantity of radioactivity contained in each gas storage tank shall be limited to less than or equal to 50,000 curies noble gases (considered as Xe-133).

~~APPLICABILITY: At all times.~~

~~ACTION:~~

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

~~2.3.2 SURVEILLANCE REQUIREMENTS~~

~~The quantity of radioactive material contained in each gas storage tank shall be determined to be within the limit at least once per 24 hours when radioactive materials are being added to the tank in accordance with the methodology and parameters in the ODCM.~~

LA.8

3.0 BASES

EXPLOSIVE GAS MONITORING INSTRUMENTATION (1/2.1.1)

The explosive gas monitoring instrumentation is provided to monitor and control the concentrations of potentially explosive gas mixtures in the waste gas holdup system. The OPERABILITY and use of this instrumentation is consistent with the requirements of General Design Criteria 60 of Appendix A to 10 CFR Part 50.

LIQUID HOLDUP TANKS (1/2.2.1)

The tanks listed in this Specification include all those outdoor tanks that are not surrounded by liners, dikes, or walls capable of holding the tank contents and that do not have tank overflows and surrounding area drains connected to the liquid radwaste treatment system.

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 values given in Appendix B, Table 2, Column 2 to 10 CFR 20, at the nearest potable water supply and the nearest surface water supply in an UNRESTRICTED AREA.

EXPLOSIVE GAS MIXTURE (1/2.3.1)

This specification is provided to ensure that the concentration of potentially explosive gas mixtures contained in the waste gas holdup system is maintained below the flammability limits of hydrogen and oxygen. Maintaining the concentration of hydrogen and oxygen below their flammability limits provides assurance that the releases of radioactive materials will be controlled in conformance with the requirements of General Design Criterion 60 of Appendix A to 10 CFR Part 50.

GAS STORAGE TANKS (1/2.3.2)

The tanks included in this specification are those tanks for which the quantity of radioactivity contained is not limited directly or indirectly by another Technical Specification to a quantity that is less than the quantity that provides assurance that in the event of an uncontrolled release of the tank's contents, the resulting total body exposure to a MEMBER OF THE PUBLIC at the nearest SITE BOUNDARY will not exceed 0.5 rem in an event of 2 hours duration.

Restricting the quantity of radioactivity contained in each gas storage tank provides assurance that in the event of an uncontrolled release of the tank's contents, the resulting total body exposure to a MEMBER OF THE PUBLIC at the nearest SITE BOUNDARY will not exceed 0.5 rem. This is consistent with NUREG-0133.

A.1

4.0 ADMINISTRATIVE CONTROLS

4.1 ~~RESPONSIBILITIES~~

A.2

~~The responsibilities of the Plant Operating Review Committee and the Safety Review Committee associated with the implementation of the Radiological Environmental Technical Specifications are delineated in the appropriate sections of Appendix A Technical Specification 6.5~~

SEE ITS 5.4

4.2 PROCEDURES AND PROGRAMS

Reference to implementation of the procedures and programs necessary for the implementation of the Radiological Environmental Technical Specifications are delineated in Appendix A Technical Specifications 6.8.1 and 6.8.4.

SEE ITS 5.6

4.3 REPORTING REQUIREMENTS

4.3.1 SPECIAL REPORTS

The activities requiring the submittal of special reports are delineated in Appendix A Technical Specification 6.9.2. The ODCM also provides a listing of special reporting requirements.

4.3.2 ROUTINE REPORTS

4.3.2.1 ANNUAL RADIOACTIVE EFFLUENT RELEASE REPORT *

The Annual Radioactive Effluent Release Report covering the operation of the unit during the previous year of operation shall be submitted prior to May 1 of each year.

The report shall include a summary of the quantities of radioactive liquid and gaseous effluents and solid waste released from the unit. The material provided shall be (1) consistent with the objectives outlined in the ODCM and PCP and (2) in conformance with 10 CFR 50.36a and Section IV.B.1 of Appendix I to 10 CFR Part 50.

A full listing of the information to be contained in the Annual Radioactive Effluent Release Report is provided in the 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.

SEE ITS 5.1

4.0 ADMINISTRATIVE CONTROLS

4.1 RESPONSIBILITIES

The responsibilities of the Plant Operating Review Committee and the Safety Review Committee associated with the implementation of the Radiological Environmental Technical Specifications are delineated in the appropriate sections of Appendix A Technical Specification 6.5.

5.4 ~~4.2~~ ~~PROCEDURES AND PROGRAMS~~ A.4

~~Reference to implementation of the procedures and programs necessary for the implementation of the Radiological Environmental Technical Specifications are delineated in Appendix A Technical Specifications 6.8.1 and 6.8.4.~~

SEE ITS 5.6

4.3 REPORTING REQUIREMENTS

4.3.1 SPECIAL REPORTS

The activities requiring the submittal of special reports are delineated in Appendix A Technical Specification 6.9.2. The ODCM also provides a listing of special reporting requirements.

4.3.2 ROUTINE REPORTS

4.3.2.1 ANNUAL RADIOACTIVE EFFLUENT RELEASE REPORT *

The Annual Radioactive Effluent Release Report covering the operation of the unit during the previous year of operation shall be submitted prior to May 1 of each year.

The report shall include a summary of the quantities of radioactive liquid and gaseous effluents and solid waste released from the unit. The material provided shall be (1) consistent with the objectives outlined in the ODCM and PCP and (2) in conformance with 10 CFR 50.36a and Section IV.B.1 of Appendix I to 10 CFR Part 50.

A full listing of the information to be contained in the Annual Radioactive Effluent Release Report is provided in the 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.

~~4.0~~ ADMINISTRATIVE CONTROLS

~~4.1~~ RESPONSIBILITIES

SEE ITS 5.1

The responsibilities of the Plant Operating Review Committee and the Safety Review Committee associated with the implementation of the Radiological Environmental Technical Specifications are delineated in the appropriate sections of Appendix A Technical Specification 6.5.

~~4.2~~ PROCEDURES AND PROGRAMS

SEE ITS 5.4

Reference to implementation of the procedures and programs necessary for the implementation of the Radiological Environmental Technical Specifications are delineated in Appendix A Technical Specifications 6.8.1 and 6.8.4.

~~4.3~~ REPORTING REQUIREMENTS

~~4.3.1~~ ~~SPECIAL REPORTS~~

~~The activities requiring the submittal of special reports are delineated in Appendix A Technical Specification 6.9.2. The ODCM also provides a listing of special reporting requirements.~~

A.7

~~4.3.2~~ ~~ROUTINE REPORTS~~

~~4.3.2.1~~ ANNUAL RADIOACTIVE EFFLUENT RELEASE REPORT *

5.6.3

The ~~Annual~~ Radioactive Effluent Release Report covering the operation of the unit during the previous year of operation shall be submitted prior to May 1 of each year.

The report shall include a summary of the quantities of radioactive liquid and gaseous effluents and solid waste released from the unit. The material provided shall be (1) consistent with the objectives outlined in the ODCM and PCP and (2) in conformance with 10 CFR 50.36a and Section IV.B.1 of Appendix I to 10 CFR Part 50.

~~A full listing of the information to be contained in the Annual Radioactive Effluent Release Report is provided in the ODCM.~~

A.6

Note to 5.6.3

* 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.

~~4.3.2.2~~ 5.6.2 ANNUAL RADIOLOGICAL ENVIRONMENTAL OPERATING REPORT*

An Annual Radiological Environmental Operating Report covering the operation of the unit during the previous calendar year shall be submitted prior to May 1 of each year. May 15 (A.

The Annual Radiological Environmental Operating Reports shall include summaries, interpretations, and an analysis of trends of the results of the Radiological Environmental Monitoring Program for the report period. The material provided shall be consistent with the objectives outlined in (1) the ODCM and (2) Sections IV.B.2, IV.B.3, and IV.C of Appendix I to 10 CFR Part 50.

A full listing of the information to be contained in the Annual Radiological Environmental Operating Report is provided in the ODCM.

~~4.2.3~~ ~~MAJOR CHANGES TO RADIOACTIVE LIQUID, GASEOUS AND SOLID WASTE TREATMENT SYSTEMS**~~

~~Licensee initiated major changes to the radioactive waste systems (liquid, gaseous and solid) shall be reported to the Commission in the Annual Radioactive Effluent Release Report for the period in which the evaluation was reviewed by the PORC. The discussion of each shall contain:~~

a. ~~A summary of the evaluation that led to the determination that the change could be made in accordance with 10 CFR Part 50.59.~~

b. ~~Sufficient detailed information to totally support the reason for the change without benefit of additional or supplemental information;~~

c. ~~A detailed description of the equipment, components and processes involved and the interfaces with other plant systems;~~

LA.3

5.6.2 * A single submittal may be made for a multiple unit station.

** ~~The information called for in this Specification will be submitted as part of the annual FSAR update.~~ LA

Amendment No. ~~51~~, ~~101~~, TSCR 98-018

SEE ITS 5.6

d. 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;

e. An evaluation of the change, which shows the expected maximum exposures to an individual in the UNRESTRICTED AREA and to the general population that differ from those previously estimated in the license application and amendments thereto;

f. 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;

g. An estimate of the exposure to plant operating personnel as a result of the change; and

h. Documentation of the fact that the change was reviewed and found acceptable by the PORC.

~~4.4~~ 5.5.1 ~~RECORD RETENTION~~ LA.2

~~Records associated with the Radiological Environmental Monitoring Program are to be retained as required by Appendix A Technical Specification 6.10.2.~~

~~4.5~~ PROCESS CONTROL PROGRAM (PCP)

~~4.5.1~~ The PCP shall be approved by the Commission prior to implementation.

~~4.5.2~~ Licensee initiated changes to the PCP:

SEE ITS 5.5.4

1. Shall be documented and records of reviews performed shall be retained as required by Appendix A Technical Specification 6.10.2.p. This documentation shall contain:

a. Sufficient information to support the change together with the appropriate analyses or evaluations justifying the change(s); and

SEE ITS 5.6

d. 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;

e. An evaluation of the change, which shows the expected maximum exposures to an individual in the UNRESTRICTED AREA and to the general population that differ from those previously estimated in the license application and amendments thereto;

f. 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;

g. An estimate of the exposure to plant operating personnel as a result of the change; and

h. Documentation of the fact that the change was reviewed and found acceptable by the PORC.

~~4.4~~ RECORD RETENTION

SEE ITS 5.5.1

Records associated with the Radiological Environmental Monitoring Program are to be retained as required by Appendix A Technical Specification 6.10.2.

~~4.5~~ PROCESS CONTROL PROGRAM (PCP)

~~4.5.1~~ The PCP shall be approved by the Commission prior to implementation.

LA.1

~~4.5~~.2 Licensee initiated changes to the PCP:

5.5.4

1. Shall be documented and records of reviews performed shall be retained as required by Appendix A Technical Specification 6.10.2.p. This documentation shall contain:

   a. Sufficient information to support the change together with the appropriate analyses or evaluations justifying the change(s); and

Amendment No. ~~51~~,

TSCR 98-018

d. 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;

e. An evaluation of the change, which shows the expected maximum exposures to an individual in the UNRESTRICTED AREA and to the general population that differ from those previously estimated in the license application and amendments thereto;

f. 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;

g. An estimate of the exposure to plant operating personnel as a result of the change; and

h. Documentation of the fact that the change was reviewed and found acceptable by the PORC.

LA.3

SEE ITS 5.5.1

4.4 RECORD RETENTION

Records associated with the Radiological Environmental Monitoring Program are to be retained as required by Appendix A Technical Specification 6.10.2.

SEE ITS 5.5.4

~~4.5~~ PROCESS CONTROL PROGRAM (PCP)

~~4.5.1~~ The PCP shall be approved by the Commission prior to implementation.

~~4.5.2~~ Licensee initiated changes to the PCP:

1. Shall be documented and records of reviews performed shall be retained as required by Appendix A Technical Specification 6.10.2.p. This documentation shall contain:

   a. Sufficient information to support the change together with the appropriate analyses or evaluations justifying the change(s); and

SEE ITS 5.5.4

b. A determination that the change will maintain the overall conformance of the solidified waste product to existing requirements of Federal, State, or other applicable regulations.

2. Shall become effective upon review and acceptance by the PORC and the approval of the Site Executive Officer.

3. Shall be submitted to the Commission as a part of or concurrent with the Annual Radioactive Effluent Release Report for the period of the report in which any change to the PCP was made. Each change shall be identified by marking in the margin of the affected pages, clearly indicating the area of the page that was changed, and shall indicate the date (e.g., month/year) the change was implemented.

5.5.1 ~~4.6~~ OFFSITE DOSE CALCULATION MANUAL (ODCM)

~~4.6.1~~ ~~The ODCM shall be approved by the Commission prior to implementation.~~ A.2

~~4.6.2~~ Licensee initiated changes to the ODCM:

5.5.1.a 1. Shall be documented and records of reviews performed shall be retained as required by Appendix A Technical Specification 6.10.2.p. This documentation shall contain:

5.5.1.a.1 a. Sufficient information to support the change together with the appropriate analyses or evaluations justifying the changes(s); and

5.5.1.a.2 b. A determination that the change will maintain the level of radioactive effluent control required pursuant to 10 CFR 20.1302, 40 CFR Part 190, 10 CFR 50.36a, and Appendix I to 10 CFR Part 50 and not adversely impact the accuracy or reliability of effluent dose or setpoint calculations;

2. Shall become effective upon ~~review and acceptance by the PORC and the~~ approval of the ~~Site Executive Officer~~. A.3

plant manager LA.3

Amendment No. ~~81~~, ~~103~~

TSCR 98-018

b. ~~A determination that the change will maintain the overall conformance of the solidified waste product to existing requirements of Federal, State, or other applicable regulations.~~

2. ~~Shall become effective upon review and acceptance by the PORC and the approval of the Site Executive Officer.~~

3. ~~Shall be submitted to the Commission as a part of or concurrent with the Annual Radioactive Effluent Release Report for the period of the report in which any change to the PCP was made. Each change shall be identified by marking in the margin of the affected pages, clearly indicating the area of the page that was changed, and shall indicate the date (e.g., month/year) the change was implemented.~~

LA.1

SEE ITS 5.5.1

4.6 OFFSITE DOSE CALCULATION MANUAL (ODCM)

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

4.6.2 Licensee initiated changes to the ODCM:

1. Shall be documented and records of reviews performed shall be retained as required by Appendix A Technical Specification 6.10.2.p. This documentation shall contain:

a. Sufficient information to support the change together with the appropriate analyses or evaluations justifying the changes(s); and

b. A determination that the change will maintain the level of radioactive effluent control required pursuant to 10 CFR 20.1302, 40 CFR Part 190, 10 CFR 50.36a, and Appendix I to 10 CFR Part 50 and not adversely impact the accuracy or reliability of effluent dose or setpoint calculations;

2. Shall become effective upon review and acceptance by the PORC and the approval of the Site Executive Officer.

A.1

5.5.1.c ~~3.~~ Shall be submitted to the Commission as a part of or concurrent with the Annual Radioactive Effluent Release Report for the period of the report in which any change to the ODCM was made. Each change shall be identified by marking in the margin of the affected pages, clearly indicating the area of the page that was changed, and shall indicate the date (e.g., month/year) the change was implemented.

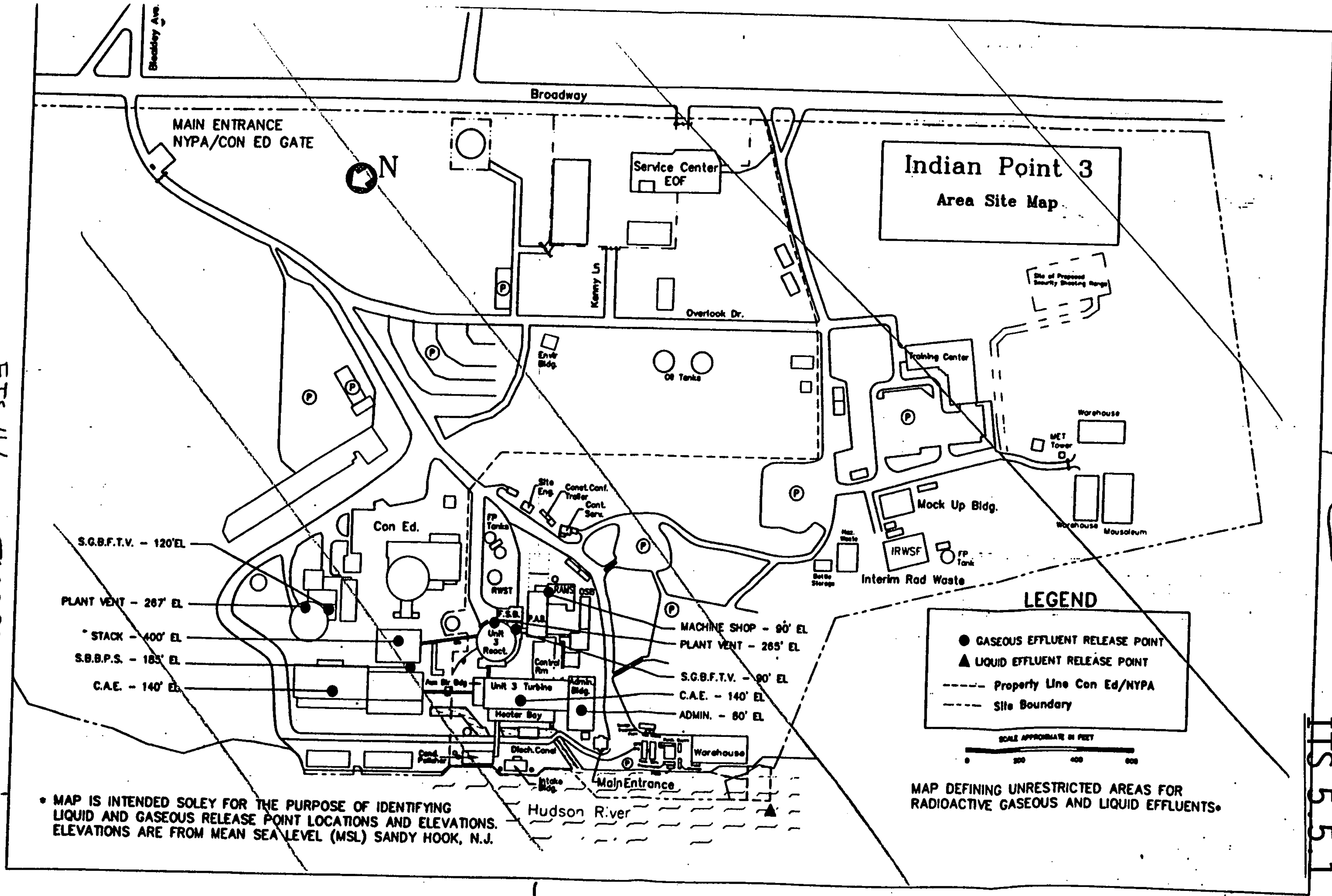
4.7 ~~MAP DEFINING UNRESTRICTED AREAS FOR RADIOACTIVE GASEOUS AND LIQUID EFFLUENTS~~

~~Information regarding radioactive gaseous and liquid effluents, which will allow identification of structures and release points as well as definition of UNRESTRICTED AREAS within the SITE BOUNDARY that are accessible to MEMBERS OF THE PUBLIC, shall be shown in Figure 4.7-1.~~

~~The definition of UNRESTRICTED AREA used in implementing the Radiological Effluent Technical Specifications has been expanded over that in 10 CFR 20.1003. The UNRESTRICTED AREA boundary may coincide with the exclusion (fenced) area boundary, as defined in 10 CFR 100.3(a), but the UNRESTRICTED AREA does not include areas over water bodies. For calculations performed pursuant to 10 CFR Part 50.36a, the concept of UNRESTRICTED AREAS, established at or beyond the SITE BOUNDARY, is utilized in the Radiological Effluent Controls to keep levels of radioactive materials in liquid and gaseous effluents as low as is reasonably achievable.~~

LA.1

Amendment No. ~~57~~ TSCR 98-018



* MAP IS INTENDED SOLEY FOR THE PURPOSE OF IDENTIFYING LIQUID AND GASEOUS RELEASE POINT LOCATIONS AND ELEVATIONS. ELEVATIONS ARE FROM MEAN SEA LEVEL (MSL) SANDY HOOK, N.J.

MAP DEFINING UNRESTRICTED AREAS FOR RADIOACTIVE GASEOUS AND LIQUID EFFLUENTS*

ETS 4.6

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ITS 5.5.1

LA.1

LA.1

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1.0 USE AND APPLICATION

1.1 Definitions

---NOTE---
The defined terms of this section appear in capitalized type and are applicable throughout these Technical Specifications and Bases.

Term	Definition
ACTIONS	ACTIONS shall be that part of a Specification that prescribes Required Actions to be taken under designated Conditions within specified Completion Times.
ACTUATION LOGIC TEST	An ACTUATION LOGIC TEST shall be the application of various simulated or actual input combinations in conjunction with each possible interlock logic state and the verification of the required logic output. The ACTUATION LOGIC TEST, as a minimum, shall include a continuity check of output devices.
AXIAL FLUX DIFFERENCE (AFD)	AFD shall be the difference in normalized flux signals between the top and bottom halves of a two section excore neutron detector.
CHANNEL CALIBRATION	A CHANNEL CALIBRATION shall be the adjustment, as necessary, of the channel so that it responds within the required range and accuracy to known input. The CHANNEL CALIBRATION shall encompass the entire channel, including the required sensor, alarm, interlock, display, and trip functions. Calibration of instrument channels with resistance temperature detector (RTD) or thermocouple sensors may consist of an inplace qualitative assessment of sensor behavior and normal calibration of the remaining adjustable devices in the channel. Whenever a sensing element is replaced, the next required CHANNEL CALIBRATION shall include an inplace cross calibration that compares the other sensing elements with the recently installed

(continued)

1.1 Definitions

CHANNEL CALIBRATION (continued)	
	sensing element. The CHANNEL CALIBRATION may be performed by means of any series of sequential, overlapping calibrations or total channel steps so that the entire channel is calibrated.
CHANNEL CHECK	A CHANNEL CHECK shall be the qualitative assessment, by observation, of channel behavior during operation. This determination shall include, where possible, comparison of the channel indication and status to other indications or status derived from independent instrument channels measuring the same parameter.
CHANNEL OPERATIONAL TEST (COT)	A COT shall be the injection of a simulated or actual signal into the channel as close to the sensor as practicable to verify the OPERABILITY of required alarm, interlock, display, and trip functions. The COT shall include adjustments, as necessary, of the required alarm, interlock, and trip setpoints so that the setpoints are within the required range and accuracy.
CORE ALTERATION	CORE ALTERATION shall be the movement of any fuel, sources, or reactivity control components, within the reactor vessel with the vessel head removed and fuel in the vessel. Suspension of CORE ALTERATIONS shall not preclude completion of movement of a component to a safe position.
CORE OPERATING LIMITS REPORT (COLR)	The COLR is the unit specific document that provides cycle specific parameter limits for the current reload cycle. These cycle specific parameter limits shall be determined for each reload cycle in accordance with Specification 5.6.5. Plant operation within these limits is addressed in individual Specifications.
DOSE EQUIVALENT I-131	DOSE EQUIVALENT I-131 shall be that concentration of I-131 (microcuries/gram) that alone would produce the

(continued)

1.1 Definitions

DOSE EQUIVALENT I-131 (continued)

same thyroid dose as the quantity and isotopic mixture of I-131, I-132, I-133, I-134, and I-135 actually present. The thyroid dose conversion factors used for this calculation shall be those listed in Table III of TID-14844, AEC, 1962, "Calculation of Distance Factors for Power and Test Reactor Sites," or those listed in Table E-7 of Regulatory Guide 1.109, Rev.1, NRC, 1977, or ICRP 30, Supplement to Part 1, page 192-212, Table titled, "Committed Dose Equivalent in Target Organs or Tissues per Intake of Unit Activity".

$\bar{E}$ – AVERAGE DISINTEGRATION ENERGY

$\bar{E}$ shall be the average (weighted in proportion to the concentration of each radionuclide in the reactor coolant at the time of sampling) of the sum of the average beta and gamma energies per disintegration (in MeV) for isotopes, other than iodines, with half lives > 10 minutes, making up at least 95% of the total noniodine activity in the coolant.

L_a

The maximum allowable primary containment leakage rate, L_a, shall be 1% of primary containment air weight per day at the calculated peak containment pressure (P_a).

LEAKAGE

LEAKAGE shall be:

a. Identified LEAKAGE

1. LEAKAGE, such as that from pump seals or valve packing (except for leakage into closed systems and reactor coolant pump (RCP) seal water injection or leakoff), that is captured and conducted to collection systems or a sump or collecting tank;

(Leakage into closed systems is leakage that can be accounted for and contained by a

(continued)

1.1 Definitions

LEAKAGE (continued)

system not directly connected to the atmosphere. Leakage past the pressurizer safety valve seats and leakage past the safety injection pressure isolation valves are examples of reactor coolant system leakage into closed systems.)

2. LEAKAGE into the containment atmosphere from sources that are both specifically located and known either not to interfere with the operation of leakage detection systems or not to be pressure boundary LEAKAGE; or

3. Reactor Coolant System (RCS) LEAKAGE through a steam generator (SG) to the Secondary System;

b. <u>Unidentified LEAKAGE</u>

All LEAKAGE (except for leakage into closed systems and RCP seal water injection or leakoff) that is not identified LEAKAGE;

c. <u>Pressure Boundary LEAKAGE</u>

LEAKAGE (except SG LEAKAGE) through a nonisolable fault in an RCS component body, pipe wall, or vessel wall.

MASTER RELAY TEST

A MASTER RELAY TEST shall consist of energizing each master relay and verifying the OPERABILITY of each relay. The MASTER RELAY TEST shall include a continuity check of each associated slave relay.

MODE

A MODE shall correspond to any one inclusive combination of core reactivity condition, power level, average reactor coolant loop temperature, and reactor

(continued)

1.1 Definitions

MODE (continued)

vessel head closure bolt tensioning specified in Table 1.1-1 with fuel in the reactor vessel.

OPERABLE – OPERABILITY

A system, subsystem, train, component, or device shall be OPERABLE or have OPERABILITY when it is capable of performing its specified safety function(s) and when all necessary attendant instrumentation, controls, normal or emergency electrical power, cooling and seal water, lubrication, and other auxiliary equipment that are required for the system, subsystem, train, component, or device to perform its specified safety function(s) are also capable of performing their related support function(s).

PHYSICS TESTS

PHYSICS TESTS shall be those tests performed to measure the fundamental nuclear characteristics of the reactor core and related instrumentation. These tests are:

a. Described in FSAR Chapter 13, Initial Tests and Operations;

b. Authorized under the provisions of 10 CFR 50.59; or

c. Otherwise approved by the Nuclear Regulatory Commission.

PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR)

The PTLR is the unit specific document that provides the reactor vessel pressure and temperature limits, including heatup and cooldown rates, for the current reactor vessel fluence period. These pressure and temperature limits shall be determined for each fluence period in accordance with Specification 5.6.6. Plant operation within these operating limits is addressed in LCO 3.4.3, "RCS Pressure and Temperature (P/T) Limits," and LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP)."

(continued)

1.1 Definitions

QUADRANT POWER TILT RATIO (QPTR)	QPTR shall be the ratio of the maximum upper excore detector calibrated output to the average of the upper excore detector calibrated outputs, or the ratio of the maximum lower excore detector calibrated output to the average of the lower excore detector calibrated outputs, whichever is greater.
RATED THERMAL POWER (RTP)	RTP shall be a total reactor core heat transfer rate to the reactor coolant of 3025 MWt.
SHUTDOWN MARGIN (SDM)	SDM shall be the instantaneous amount of reactivity by which the reactor is subcritical or would be subcritical from its present condition assuming: a. All rod cluster control assemblies (RCCAs) are fully inserted except for the single RCCA of highest reactivity worth, which is assumed to be fully withdrawn. With any RCCA not capable of being fully inserted, the reactivity worth of the RCCA must be accounted for in the determination of SDM; and b. In MODES 1 and 2, the fuel and moderator temperatures are changed to the hot zero power level.
SLAVE RELAY TEST	A SLAVE RELAY TEST shall consist of energizing each slave relay and verifying the OPERABILITY of each slave relay. The SLAVE RELAY TEST shall include, as a minimum, a continuity check of associated testable actuation devices.
STAGGERED TEST BASIS	A STAGGERED TEST BASIS shall consist of the testing of one of the systems, subsystems, channels, or other designated components during the interval specified by the Surveillance Frequency, so that all systems, subsystems, channels, or other designated components are tested during *n* Surveillance Frequency intervals, where *n* is the total number of systems, subsystems, channels, or other designated components in the associated function.

(continued)

1.1 Definitions

THERMAL POWER	THERMAL POWER shall be the total reactor core heat transfer rate to the reactor coolant.
TRIP ACTUATING DEVICE OPERATIONAL TEST (TADOT)	A TADOT shall consist of operating the trip actuating device and verifying the OPERABILITY of required alarm, interlock, display, and trip functions. The TADOT shall include adjustment, as necessary, of the trip actuating device so that it actuates at the required setpoint within the required accuracy.

1.1 Definitions

Table 1.1-1 (page 1 of 1)
MODES

MODE	TITLE	REACTIVITY CONDITION (k_{eff})	% RATED THERMAL POWER[a]	AVERAGE REACTOR COOLANT TEMPERATURE (°F)
1	Power Operation	≥ 0.99	> 5	NA
2	Startup	≥ 0.99	≤ 5	NA
3	Hot Standby	< 0.99	NA	≥ 350
4	Hot Shutdown[b]	< 0.99	NA	350 > T_{avg} > 200
5	Cold Shutdown[b]	< 0.99	NA	≤ 200
6	Refueling[c]	NA	NA	NA

(a) Excluding decay heat.

(b) All reactor vessel head closure bolts fully tensioned.

(c) One or more reactor vessel head closure bolts less than fully tensioned.

1.0 USE AND APPLICATION

1.2 Logical Connectors

PURPOSE

The purpose of this section is to explain the meaning of logical connectors.

Logical connectors are used in Technical Specifications (TS) to discriminate between, and yet connect, discrete Conditions, Required Actions, Completion Times, Surveillances, and Frequencies. The only logical connectors that appear in TS are AND and OR. The physical arrangement of these connectors constitutes logical conventions with specific meanings.

BACKGROUND

Several levels of logic may be used to state Required Actions. These levels are identified by the placement (or nesting) of the logical connectors and by the number assigned to each Required Action. The first level of logic is identified by the first digit of the number assigned to a Required Action and the placement of the logical connector in the first level of nesting (i.e., left justified with the number of the Required Action). The successive levels of logic are identified by additional digits of the Required Action number and by successive indentations of the logical connectors.

When logical connectors are used to state a Condition, Completion Time, Surveillance, or Frequency, only the first level of logic is used, and the logical connector is left justified with the statement of the Condition, Completion Time, Surveillance, or Frequency.

EXAMPLES

The following examples illustrate the use of logical connectors.

(continued)

1.2 Logical Connectors

EXAMPLES (continued)

EXAMPLE 1.2-1

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. LCO not met.	A.1 Verify . . . AND A.2 Restore . . .	

In this example the logical connector AND is used to indicate that when in Condition A, both Required Actions A.1 and A.2 must be completed.

(continued)

1.2 Logical Connectors

EXAMPLES (continued)

EXAMPLE 1.2-2

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. LCO not met.	A.1 Trip . . . OR A.2.1 Verify . . . AND A.2.2.1 Reduce . . . OR A.2.2.2 Perform . . . OR A.3 Align . . .	

This example represents a more complicated use of logical connectors. Required Actions A.1, A.2, and A.3 are alternative choices, only one of which must be performed as indicated by the use of the logical connector OR and the left justified placement. Any one of these three Actions may be chosen. If A.2 is chosen, then both A.2.1 and A.2.2 must be performed as indicated by the logical connector AND. Required Action A.2.2 is met by performing A.2.2.1 or A.2.2.2. The indented position of the logical connector OR indicates that A.2.2.1 and A.2.2.2 are alternative choices, only one of which must be performed.

1.0 USE AND APPLICATION

1.3 Completion Times

PURPOSE

The purpose of this section is to establish the Completion Time convention and to provide guidance for its use.

BACKGROUND

Limiting Conditions for Operation (LCOs) specify minimum requirements for ensuring safe operation of the unit. The ACTIONS associated with an LCO state Conditions that typically describe the ways in which the requirements of the LCO can fail to be met. Specified with each stated Condition are Required Action(s) and Completion Time(s).

DESCRIPTION

The Completion Time is the amount of time allowed for completing a Required Action. It is referenced to the time of discovery of a situation (e.g., inoperable equipment or variable not within limits) that requires entering an ACTIONS Condition unless otherwise specified, providing the unit is in a MODE or specified condition stated in the Applicability of the LCO. Required Actions must be completed prior to the expiration of the specified Completion Time. An ACTIONS Condition remains in effect and the Required Actions apply until the Condition no longer exists or the unit is not within the LCO Applicability.

If situations are discovered that require entry into more than one Condition at a time within a single LCO (multiple Conditions), the Required Actions for each Condition must be performed within the associated Completion Time. When in multiple Conditions, separate Completion Times are tracked for each Condition starting from the time of discovery of the situation that required entry into the Condition.

Once a Condition has been entered, subsequent trains, subsystems, components, or variables expressed in the Condition, discovered to be inoperable or not within limits, will not result in separate entry into the Condition, unless specifically stated. The Required Actions of the Condition continue to apply to each

(continued)

1.3 Completion Times

DESCRIPTION (continued)

additional failure, with Completion Times based on initial entry into the Condition.

However, when a <u>subsequent</u> train, subsystem, component, or variable expressed in the Condition is discovered to be inoperable or not within limits, the Completion Time(s) may be extended. To apply this Completion Time extension, two criteria must first be met. The subsequent inoperability:

a. Must exist concurrent with the <u>first</u> inoperability; and

b. Must remain inoperable or not within limits after the first inoperability is resolved.

The total Completion Time allowed for completing a Required Action to address the subsequent inoperability shall be limited to the more restrictive of either:

a. The stated Completion Time, as measured from the initial entry into the Condition, plus an additional 24 hours; or

b. The stated Completion Time as measured from discovery of the subsequent inoperability.

The above Completion Time extensions do not apply to those Specifications that have exceptions that allow completely separate re-entry into the Condition (for each train, subsystem, component, or variable expressed in the Condition) and separate tracking of Completion Times based on this re-entry. These exceptions are stated in individual Specifications.

The above Completion Time extension does not apply to a Completion Time with a modified "time zero." This modified "time zero" may be expressed as a repetitive time (i.e., "once per 8 hours," where the Completion Time is referenced from a previous completion of the Required Action versus the time of Condition

(continued)

1.3 Completion Times

DESCRIPTION (continued)

entry) or as a time modified by the phrase "from discovery . . ." Example 1.3-3 illustrates one use of this type of Completion Time. The 10 day Completion Time specified for Conditions A and B in Example 1.3-3 may not be extended.

EXAMPLES

The following examples illustrate the use of Completion Times with different types of Conditions and changing Conditions.

EXAMPLE 1.3-1

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 36 hours

Condition B has two Required Actions. Each Required Action has its own separate Completion Time. Each Completion Time is referenced to the time that Condition B is entered.

The Required Actions of Condition B are to be in MODE 3 within 6 hours AND in MODE 5 within 36 hours. A total of 6 hours is allowed for reaching MODE 3 and a total of 36 hours (not 42 hours) is allowed for reaching MODE 5 from the time that Condition B was entered. If MODE 3 is reached within 3 hours, the time allowed for reaching MODE 5 is the next 33 hours because the total time allowed for reaching MODE 5 is 36 hours.

If Condition B is entered while in MODE 3, the time allowed for reaching MODE 5 is the next 36 hours.

(continued)

1.3 Completion Times

EXAMPLES

EXAMPLE 1.3-3 (continued)

EXAMPLE 1.3-2

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One pump inoperable.	A.1 Restore pump to OPERABLE status.	7 days
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 36 hours

When a pump is declared inoperable, Condition A is entered. If the pump is not restored to OPERABLE status within 7 days, Condition B is also entered and the Completion Time clocks for Required Actions B.1 and B.2 start. If the inoperable pump is restored to OPERABLE status after Condition B is entered, Condition A and B are exited, and therefore, the Required Actions of Condition B may be terminated.

When a second pump is declared inoperable while the first pump is still inoperable, Condition A is not re-entered for the second pump. LCO 3.0.3 is entered, since the ACTIONS do not include a Condition for more than one inoperable pump. The Completion Time clock for Condition A does not stop after LCO 3.0.3 is entered, but continues to be tracked from the time Condition A was initially entered.

While in LCO 3.0.3, if one of the inoperable pumps is restored to OPERABLE status and the Completion Time for Condition A has not

(continued)

1.3 Completion Times

EXAMPLES

EXAMPLE 1.3-2 (continued)

expired, LCO 3.0.3 may be exited and operation continued in accordance with Condition A.

While in LCO 3.0.3, if one of the inoperable pumps is restored to OPERABLE status and the Completion Time for Condition A has expired, LCO 3.0.3 may be exited and operation continued in accordance with Condition B. The Completion Time for Condition B is tracked from the time the Condition A Completion Time expired.

On restoring one of the pumps to OPERABLE status, the Condition A Completion Time is not reset, but continues from the time the first pump was declared inoperable. This Completion Time may be extended if the pump restored to OPERABLE status was the first inoperable pump. A 24 hour extension to the stated 7 days is allowed, provided this does not result in the second pump being inoperable for > 7 days.

(continued)

1.3 Completion Times

EXAMPLES

EXAMPLE 1.3-3 (continued)

EXAMPLE 1.3-3

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One Function X train inoperable.	A.1 Restore Function X train to OPERABLE status.	7 days AND 10 days from discovery of failure to meet the LCO
B. One Function Y train inoperable.	B.1 Restore Function Y train to OPERABLE status.	72 hours AND 10 days from discovery of failure to meet the LCO
C. One Function X train inoperable. AND One Function Y train inoperable.	C.1 Restore Function X train to OPERABLE status. OR C.2 Restore Function Y train to OPERABLE status.	72 hours 72 hours

(continued)

1.3 Completion Times

EXAMPLES

EXAMPLE 1.3-3 (continued)

When one Function X train and one Function Y train are inoperable, Condition A and Condition B are concurrently applicable. The Completion Times for Condition A and Condition B are tracked separately for each train starting from the time each train was declared inoperable and the Condition was entered. A separate Completion Time is established for Condition C and tracked from the time the second train was declared inoperable (i.e., the time the situation described in Condition C was discovered).

If Required Action C.2 is completed within the specified Completion Time, Conditions B and C are exited. If the Completion Time for Required Action A.1 has not expired, operation may continue in accordance with Condition A. The remaining Completion Time in Condition A is measured from the time the affected train was declared inoperable (i.e., initial entry into Condition A).

The Completion Times of Conditions A and B are modified by a logical connector with a separate 10 day Completion Time measured from the time it was discovered the LCO was not met. In this example, without the separate Completion Time, it would be possible to alternate between Conditions A, B, and C in such a manner that operation could continue indefinitely without ever restoring systems to meet the LCO. The separate Completion Time modified by the phrase "from discovery of failure to meet the LCO" is designed to prevent indefinite continued operation while not meeting the LCO. This Completion Time allows for an exception to the normal "time zero" for beginning the Completion Time "clock". In this instance, the Completion Time "time zero" is specified as commencing at the time the LCO was initially not met, instead of at the time the associated Condition was entered.

(continued)

1.3 Completion Times

EXAMPLES (continued)

EXAMPLE 1.3-4

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more valves inoperable.	A.1 Restore valve(s) to OPERABLE status.	4 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 4.	6 hours 12 hours

A single Completion Time is used for any number of valves inoperable at the same time. The Completion Time associated with Condition A is based on the initial entry into Condition A and is not tracked on a per valve basis. Declaring subsequent valves inoperable, while Condition A is still in effect, does not trigger the tracking of separate Completion Times.

Once one of the valves has been restored to OPERABLE status, the Condition A Completion Time is not reset, but continues from the time the first valve was declared inoperable. The Completion Time may be extended if the valve restored to OPERABLE status was the first inoperable valve. The Condition A Completion Time may be extended for up to 4 hours provided this does not result in any subsequent valve being inoperable for > 4 hours.

If the Completion Time of 4 hours (including the extension) expires while one or more valves are still inoperable, Condition B is entered.

(continued)

1.3 Completion Times

EXAMPLES (continued)

EXAMPLE 1.3-5

ACTIONS

-----------------------------NOTE-----------------------------
Separate Condition entry is allowed for each inoperable valve.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more valves inoperable.	A.1 Restore valve to OPERABLE status.	4 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 4.	6 hours 12 hours

The Note above the ACTIONS Table is a method of modifying how the Completion Time is tracked. If this method of modifying how the Completion Time is tracked was applicable only to a specific Condition, the Note would appear in that Condition rather than at the top of the ACTIONS Table.

The Note allows Condition A to be entered separately for each inoperable valve, and Completion Times tracked on a per valve basis. When a valve is declared inoperable, Condition A is entered and its Completion Time starts. If subsequent valves are declared inoperable, Condition A is entered for each valve and separate Completion Times start and are tracked for each valve.

(continued)

1.3 Completion Times

EXAMPLES

EXAMPLE 1.3-5 (continued)

If the Completion Time associated with a valve in Condition A expires, Condition B is entered for that valve. If the Completion Times associated with subsequent valves in Condition A expire, Condition B is entered separately for each valve and separate Completion Times start and are tracked for each valve. If a valve that caused entry into Condition B is restored to OPERABLE status, Condition B is exited for that valve.

Since the Note in this example allows multiple Condition entry and tracking of separate Completion Times, Completion Time extensions do not apply.

EXAMPLE 1.3-6

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One channel inoperable.	A.1 Perform SR 3.x.x.x. OR A.2 Reduce THERMAL POWER to ≤ 50% RTP.	Once per 8 hours 8 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	6 hours

(continued)

1.3 Completion Times

EXAMPLES

EXAMPLE 1.3-6 (continued)

Entry into Condition A offers a choice between Required Action A.1 or A.2. Required Action A.1 has a "once per" Completion Time, which qualifies for the 25% extension, per SR 3.0.2, to each performance after the initial performance. The initial 8 hour interval of Required Action A.1 begins when Condition A is entered and the initial performance of Required Action A.1 must be complete within the first 8 hour interval. If Required Action A.1 is followed, and the Required Action is not met within the Completion Time (plus the extension allowed by SR 3.0.2), Condition B is entered. If Required Action A.2 is followed and the Completion Time of 8 hours is not met, Condition B is entered.

If after entry into Condition B, Required Action A.1 or A.2 is met, Condition B is exited and operation may then continue in Condition A.

(continued)

1.3 Completion Times

EXAMPLES (continued)

EXAMPLE 1.3-7

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One subsystem inoperable.	A.1 Verify affected subsystem isolated.	1 hour AND Once per 8 hours thereafter
	AND	
	A.2 Restore subsystem to OPERABLE status.	72 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	6 hours
	AND	
	B.2 Be in MODE 5.	36 hours

Required Action A.1 has two Completion Times. The 1 hour Completion Time begins at the time the Condition is entered and each "Once per 8 hours thereafter" interval begins upon performance of Required Action A.1.

(continued)

1.3 Completion Times

EXAMPLES

EXAMPLE 1.3-7 (continued)

If after Condition A is entered, Required Action A.1 is not met within either the initial 1 hour or any subsequent 8 hour interval from the previous performance (plus the extension allowed by SR 3.0.2), Condition B is entered. The Completion Time clock for Condition A does not stop after Condition B is entered, but continues from the time Condition A was initially entered. If Required Action A.1 is met after Condition B is entered, Condition B is exited and operation may continue in accordance with Condition A, provided the Completion Time for Required Action A.2 has not expired.

IMMEDIATE COMPLETION TIME

When "Immediately" is used as a Completion Time, the Required Action should be pursued without delay and in a controlled manner.

1.0 USE AND APPLICATION

1.4 Frequency

PURPOSE

The purpose of this section is to define the proper use and application of Frequency requirements.

DESCRIPTION

Each Surveillance Requirement (SR) has a specified Frequency in which the Surveillance must be met in order to meet the associated LCO. An understanding of the correct application of the specified Frequency is necessary for compliance with the SR.

The "specified Frequency" is referred to throughout this section and each of the Specifications of Section 3.0, Surveillance Requirement (SR) Applicability. The "specified Frequency" consists of the requirements of the Frequency column of each SR as well as certain Notes in the Surveillance column that modify performance requirements.

Situations where a Surveillance could be required (i.e., its Frequency could expire), but where it is not possible or not desired that it be performed until sometime after the associated LCO is within its Applicability, represent potential SR 3.0.4 conflicts. To avoid these conflicts, the SR (i.e., the Surveillance or the Frequency) is stated such that it is only "required" when it can be and should be performed. With an SR satisfied, SR 3.0.4 imposes no restriction.

EXAMPLES

The following examples illustrate the various ways that Frequencies are specified. In these examples, the Applicability of the LCO (LCO not shown) is MODES 1, 2, and 3.

(continued)

1.4 Frequency

EXAMPLES (continued)

EXAMPLE 1.4-1

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
Perform CHANNEL CHECK.	12 hours

Example 1.4-1 contains the type of SR most often encountered in the Technical Specifications (TS). The Frequency specifies an interval (12 hours) during which the associated Surveillance must be performed at least one time. Performance of the Surveillance initiates the subsequent interval. Although the Frequency is stated as 12 hours, an extension of the time interval to 1.25 times the stated Frequency is allowed by SR 3.0.2 for operational flexibility. The measurement of this interval continues at all times, even when the SR is not required to be met per SR 3.0.1 (such as when the equipment is inoperable, a variable is outside specified limits, or the unit is outside the Applicability of the LCO). If the interval specified by SR 3.0.2 is exceeded while the unit is in a MODE or other specified condition in the Applicability of the LCO, and the performance of the Surveillance is not otherwise modified (refer to Example 1.4-3), then SR 3.0.3 becomes applicable.

If the interval as specified by SR 3.0.2 is exceeded while the unit is not in a MODE or other specified condition in the Applicability of the LCO for which performance of the SR is required, the Surveillance must be performed within the Frequency requirements of SR 3.0.2 prior to entry into the MODE or other specified condition. Failure to do so would result in a violation of SR 3.0.4.

(continued)

1.4 Frequency

EXAMPLES (continued)

EXAMPLE 1.4-2

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
Verify flow is within limits.	Once within 12 hours after ≥ 25% RTP AND 24 hours thereafter

Example 1.4-2 has two Frequencies. The first is a one time performance Frequency, and the second is of the type shown in Example 1.4-1. The logical connector "AND" indicates that both Frequency requirements must be met. Each time reactor power is increased from a power level < 25% RTP to ≥ 25% RTP, the Surveillance must be performed within 12 hours.

The use of "once" indicates a single performance will satisfy the specified Frequency (assuming no other Frequencies are connected by "AND"). This type of Frequency does not qualify for the 25% extension allowed by SR 3.0.2. "Thereafter" indicates future performances must be established per SR 3.0.2, but only after a specified condition is first met (i.e., the "once" performance in this example). If reactor power decreases to < 25% RTP, the measurement of both intervals stops. New intervals start upon reactor power reaching 25% RTP.

(continued)

1.4 Frequency

EXAMPLES (continued)

EXAMPLE 1.4-3

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
-----------------NOTE------------------- Not required to be performed until 12 hours after ≥ 25% RTP. -- Perform channel adjustment.	7 days

The interval continues, whether or not the unit operation is < 25% RTP between performances.

As the Note modifies the required performance of the Surveillance, it is construed to be part of the "specified Frequency." Should the 7 day interval be exceeded while operation is < 25% RTP, this Note allows 12 hours after power reaches ≥ 25% RTP to perform the Surveillance. The Surveillance is still considered to be performed within the "specified Frequency." Therefore, if the Surveillance were not performed within the 7 day (plus the extension allowed by SR 3.0.2) interval, but operation was < 25% RTP, it would not constitute a failure of the SR or failure to meet the LCO. Also, no violation of SR 3.0.4 occurs when changing MODES, even with the 7 day Frequency not met, provided operation does not exceed 12 hours with power ≥ 25% RTP.

Once the unit reaches 25% RTP, 12 hours would be allowed for completing the Surveillance. If the Surveillance were not performed within this 12 hour interval, there would then be a failure to perform a Surveillance within the specified Frequency, and the provisions of SR 3.0.3 would apply.

2.0 SAFETY LIMITS (SLs)

2.1 SLs

2.1.1 Reactor Core SLs

In MODES 1 and 2, the combination of THERMAL POWER, Reactor Vessel inlet temperature, and pressurizer pressure shall not exceed the SLs specified in Figure 2.1-1.

2.1.2 RCS Pressure SL

In MODES 1, 2, 3, 4, 5, and in MODE 6 when the reactor vessel head is on, the RCS pressure shall be maintained ≤ 2735 psig.

2.2 SL Violations

2.2.1 If SL 2.1.1 is violated, restore compliance and be in MODE 3 within 1 hour.

2.2.2 If SL 2.1.2 is violated:

2.2.2.1 In MODE 1 or 2, restore compliance and be in MODE 3 within 1 hour.

2.2.2.2 In MODE 3, 4, 5, or 6, restore compliance within 5 minutes.

This curve does not provide allowable limits for normal operation.
(see Pressure, Temperature and Flow DNB limits, for DNB limits)

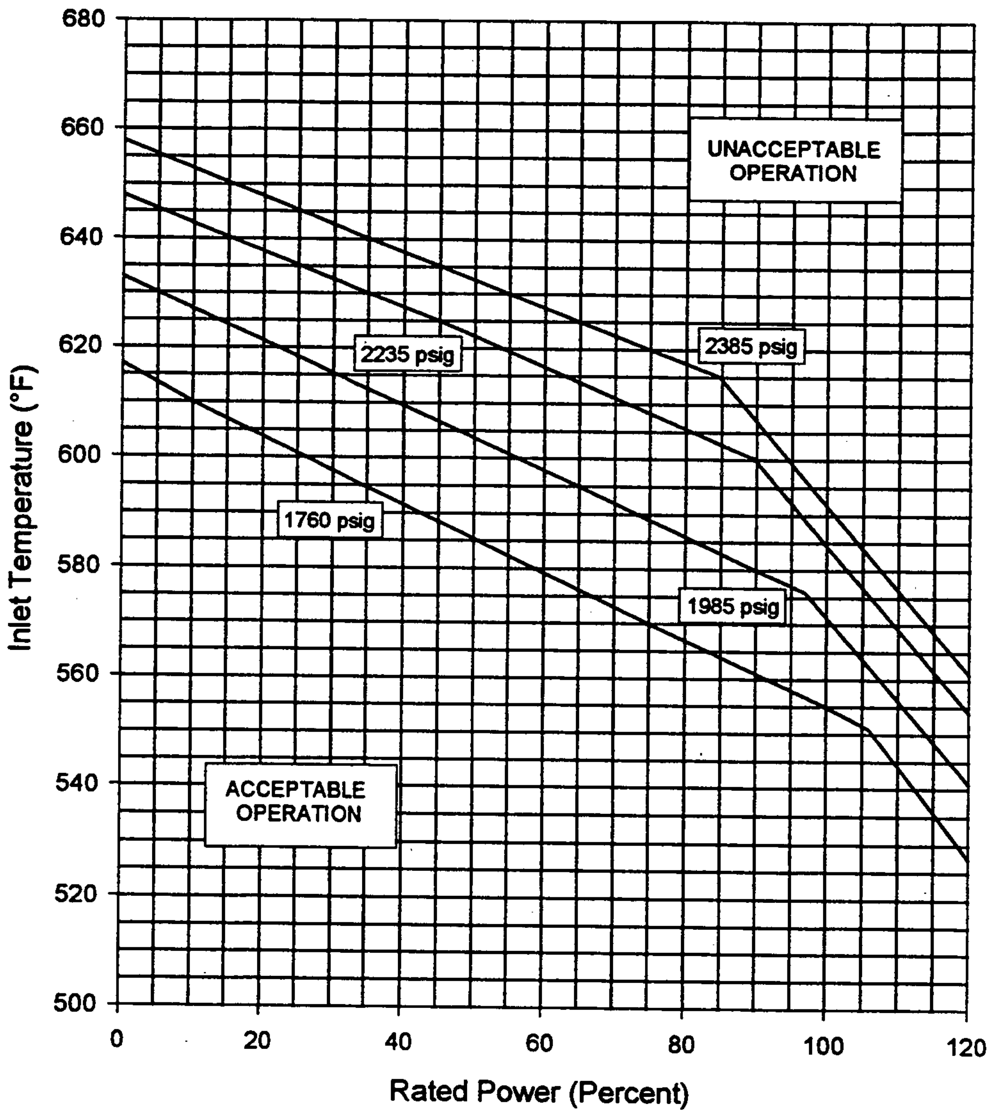

Figure 2.1-1
Rated Power (Percent of 3025 MWt)
100 PERCENT RATED POWER IS EQUIVALENT TO 3025 MWt
Pressures and temperatures do not include allowance for instrument error.

3.0 LIMITING CONDITION FOR OPERATION (LCO) APPLICABILITY

LCO 3.0.1

LCOs shall be met during the MODES or other specified conditions in the Applicability, except as provided in LCO 3.0.2 and LCO 3.0.7.

LCO 3.0.2

Upon discovery of a failure to meet an LCO, the Required Actions of the associated Conditions shall be met, except as provided in LCO 3.0.5 and LCO 3.0.6.

If the LCO is met or is no longer applicable prior to expiration of the specified Completion Time(s), completion of the Required Action(s) is not required unless otherwise stated.

LCO 3.0.3

When an LCO is not met and the associated ACTIONS are not met, an associated ACTION is not provided, or if directed by the associated ACTIONS, the unit shall be placed in a MODE or other specified condition in which the LCO is not applicable. Action shall be initiated within 1 hour to place the unit, as applicable, in:

a. MODE 3 within 7 hours;

b. MODE 4 within 13 hours; and

c. MODE 5 within 37 hours.

Exceptions to this Specification are stated in the individual Specifications.

Where corrective measures are completed that permit operation in accordance with the LCO or ACTIONS, completion of the actions required by LCO 3.0.3 is not required.

LCO 3.0.3 is only applicable in MODES 1, 2, 3, and 4.

3.0 LCO APPLICABILITY

LCO 3.0.4

When an LCO is not met, entry into a MODE or other specified condition in the Applicability shall not be made except when the associated ACTIONS to be entered permit continued operation in the MODE or other specified condition in the Applicability for an unlimited period of time. This Specification shall not prevent changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.

Exceptions to this Specification are stated in the individual Specifications. These exceptions allow entry into MODES or other specified conditions in the Applicability when the associated ACTIONS to be entered allow unit operation in the MODE or other specified condition in the Applicability only for a limited period of time.

LCO 3.0.4 is only applicable for entry into a MODE or other specified condition in the Applicability in MODES 1, 2, 3, and 4.

LCO 3.0.5

Equipment removed from service or declared inoperable to comply with ACTIONS may be returned to service under administrative control solely to perform testing required to demonstrate its OPERABILITY or the OPERABILITY of other equipment. This is an exception to LCO 3.0.2 for the system returned to service under administrative control to perform the testing required to demonstrate OPERABILITY.

LCO 3.0.6

When a supported system LCO is not met solely due to a support system LCO not being met, the Conditions and Required Actions associated with this supported system are not required to be entered. Only the support system LCO ACTIONS are required to be entered. This is an exception to LCO 3.0.2 for the supported system. In this event, an evaluation shall be performed in accordance with Specification 5.5.14, "Safety Function Determination Program (SFDP)." If a loss of safety function is determined to exist by this program, the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists are required to be entered.

3.0 LCO APPLICABILITY

LCO 3.0.6 (continued)

When a support system's Required Action directs a supported system to be declared inoperable or directs entry into Conditions and Required Actions for a supported system, the applicable Conditions and Required Actions shall be entered in accordance with LCO 3.0.2.

LCO 3.0.7

Test Exception LCOs, such as 3.1.8, allow specified Technical Specification (TS) requirements to be changed to permit performance of special tests and operations. Unless otherwise specified, all other TS requirements remain unchanged. Compliance with Test Exception LCOs is optional. When a Test Exception LCO is desired to be met but is not met, the ACTIONS of the Test Exception LCO shall be met. When a Test Exception LCO is not desired to be met, entry into a MODE or other specified condition in the Applicability shall be made in accordance with the other applicable Specifications.

3.0 SURVEILLANCE REQUIREMENT (SR) APPLICABILITY

SR 3.0.1

SRs shall be met during the MODES or other specified conditions in the Applicability for individual LCOs, unless otherwise stated in the SR. Failure to meet a Surveillance, whether such failure is experienced during the performance of the Surveillance or between performances of the Surveillance, shall be failure to meet the LCO. Failure to perform a Surveillance within the specified Frequency shall be failure to meet the LCO except as provided in SR 3.0.3. Surveillances do not have to be performed on inoperable equipment or variables outside specified limits.

SR 3.0.2

The specified Frequency for each SR is met if the Surveillance is performed within 1.25 times the interval specified in the Frequency, as measured from the previous performance or as measured from the time a specified condition of the Frequency is met.

For Frequencies specified as "once," the above interval extension does not apply.

If a Completion Time requires periodic performance on a "once per . . ." basis, the above Frequency extension applies to each performance after the initial performance.

Exceptions to this Specification are stated in the individual Specifications.

SR 3.0.3

If it is discovered that a Surveillance was not performed within its specified Frequency, then compliance with the requirement to declare the LCO not met may be delayed, from the time of discovery, up to 24 hours or up to the limit of the specified Frequency, whichever is less. This delay period is permitted to allow performance of the Surveillance.

If the Surveillance is not performed within the delay period, the LCO must immediately be declared not met, and the applicable Condition(s) must be entered.

(continued)

3.0 SR APPLICABILITY

SR 3.0.3 (continued)

When the Surveillance is performed within the delay period and the Surveillance is not met, the LCO must immediately be declared not met, and the applicable Condition(s) must be entered.

SR 3.0.4 Entry into a MODE or other specified condition in the Applicability of an LCO shall not be made unless the LCO's Surveillances have been met within their specified Frequency. This provision shall not prevent entry into MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.

SR 3.0.4 is only applicable for entry into a MODE or other specified condition in the Applicability in MODES 1, 2, 3 and 4.

3.1 REACTIVITY CONTROL SYSTEMS

3.1.1 SHUTDOWN MARGIN (SDM)

LCO 3.1.1 SDM shall be within the limits specified in the COLR.

APPLICABILITY: MODE 2 with $k_{eff} < 1.0$,
MODES 3, 4, and 5.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. SDM not within limit.	A.1 Initiate boration to restore SDM to within limit.	15 minutes

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.1.1.1 Verify SDM is within the limits specified in the COLR.	24 hours

3.1 REACTIVITY CONTROL SYSTEMS

3.1.2 Core Reactivity

LCO 3.1.2 The measured core reactivity shall be within ± 1% $\Delta k/k$ of predicted values.

APPLICABILITY: MODE 1

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. Measured core reactivity not within limit.	A.1	Re-evaluate core design and safety analysis, and determine that the reactor core is acceptable for continued operation.	7 days
	<u>AND</u>		
	A.2	Establish appropriate operating restrictions and SRs.	7 days
B. Required Action and associated Completion Time not met.	B.1	Be in MODE 2.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.2.1	--------------------NOTE-------------------- The predicted reactivity values may be adjusted (normalized) to correspond to the measured core reactivity prior to exceeding a fuel burnup of 60 effective full power days (EFPD) after each fuel loading. -- Verify measured core reactivity is within ± 1% $\Delta k/k$ of predicted values.	Once prior to entering MODE 1 after each refueling AND -----NOTE------ Only required after 60 EFPD -------------- 31 EFPD thereafter

3.1 REACTIVITY CONTROL SYSTEMS

3.1.3 Moderator Temperature Coefficient (MTC)

LCO 3.1.3 The MTC shall be maintained within the limits specified in the COLR. The maximum upper limit shall be $\leq 0.0\ \Delta k/k°F$ at hot zero power.

APPLICABILITY: MODE 1 and MODE 2 with $k_{eff} \geq 1.0$ for the upper MTC limit, MODES 1, 2, and 3 for the lower MTC limit.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. MTC not within upper limit.	A.1	Establish administrative withdrawal limits for control banks to maintain MTC within limit.	24 hours
B. Required Action and associated Completion Time of Condition A not met.	B.1	Be in MODE 2 with $k_{eff} < 1.0$.	6 hours
C. MTC not within lower limit.	C.1	Be in MODE 4.	12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.3.1	Verify MTC is within upper limit.	Once prior to entering MODE 1 after each refueling
SR 3.1.3.2	------------------NOTES--------------------- 1. Not required to be performed until 7 effective full power days (EFPD) after reaching the equivalent of an equilibrium RTP all rods out (ARO) boron concentration of 300 ppm. 2. If the MTC is more negative than the 300 ppm Surveillance limit (not LCO limit) specified in the COLR, SR 3.1.3.2 shall be repeated once per 14 EFPD during the remainder of the fuel cycle. 3. SR 3.1.3.2 need not be repeated if the MTC measured at the equivalent of equilibrium RTP-ARO boron concentration of ≤ 60 ppm is less negative than the 60 ppm Surveillance limit specified in the COLR. --- Verify MTC is within lower limit.	Once each cycle

3.1 REACTIVITY CONTROL SYSTEMS

3.1.4 Rod Group Alignment Limits

LCO 3.1.4 All shutdown and control rods shall be OPERABLE, with rod group alignment limits as follows:

a. When THERMAL POWER is > 85% RTP,

1. Groups with step counter demand position ≤ 212 steps shall have all individual indicated rod positions ≤ ± 12 steps of their group step counter demand position; and

2. Groups with step counter demand position > 212 steps shall have all individual indicated rod positions ≤ +17 steps and -12 steps of their group step counter demand position

b. When THERMAL POWER is ≤ 85% RTP, all individual indicated rod positions shall be ≤ ± 18 steps of their group step counter demand position.

APPLICABILITY: MODES 1 and 2.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more rod(s) untrippable.	A.1.1 Verify SDM is within the limits specified in the COLR.	1 hour
	<u>OR</u>	
	A.1.2 Initiate boration to restore SDM to within limit.	1 hour
	<u>AND</u>	
	A.2 Be in MODE 3.	6 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. One rod not within alignment limits.	B.1	Restore rod to within alignment limits.	1 hour
	<u>OR</u>		
	B.2.1.1	Verify SDM is within the limits specified in the COLR.	1 hour
		<u>OR</u>	
	B.2.1.2	Initiate boration to restore SDM to within limit.	1 hour
	<u>AND</u>		
	B.2.2	Reduce THERMAL POWER to $\leq$ 75% RTP.	2 hours
	<u>AND</u>		
	B.2.3	Verify SDM is within the limits specified in the COLR.	Once per 12 hours
	<u>AND</u>		
	B.2.4	Perform SR 3.2.1.1.	72 hours
	<u>AND</u>		
	B.2.5	Perform SR 3.2.2.1.	72 hours
	<u>AND</u>		
			(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B (continued)	B.2.6	Re-evaluate safety analyses and confirm results remain valid for duration of operation under these conditions.	5 days
C. Required Action and associated Completion Time of Condition B not met.	C.1	Be in MODE 3.	6 hours
D. More than one rod not within alignment limit.	D.1.1	Verify SDM is within the limits specified in the COLR.	1 hour
	<u>OR</u>		
	D.1.2	Initiate boration to restore required SDM to within limit.	1 hour
	<u>AND</u>		
	D.2	Be in MODE 3.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.4.1	----------------- NOTE ----------------- Not required to be performed for individual control rods until 1 hour after completion of control rod movement. -- Verify individual rod positions within alignment limit.	12 hours
SR 3.1.4.2	Verify rod freedom of movement (trippability) by moving each rod not fully inserted in the core ≥ 10 steps in one direction.	92 days
SR 3.1.4.3	Verify rod drop time of each rod, from the fully withdrawn position, is ≤ 1.8 seconds from the loss of stationary gripper coil voltage to dashpot entry, with: a. $T_{avg} \geq 500°F$; and b. All reactor coolant pumps operating.	Prior to reactor criticality after each removal of the reactor head

3.1 REACTIVITY CONTROL SYSTEMS

3.1.5 Shutdown Bank Insertion Limits

LCO 3.1.5 Each shutdown bank shall be within insertion limits specified in the COLR.

APPLICABILITY: MODE 1,
MODE 2 with any control bank not fully inserted.

-------------------------NOTE-------------------------
This LCO is not applicable while performing SR 3.1.4.2.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more shutdown banks not within limits.	A.1.1 Verify SDM is within the limits specified in the COLR. <u>OR</u> A.1.2 Initiate boration to restore SDM to within limit. <u>AND</u> A.2 Restore shutdown banks to within limits.	1 hour 1 hour 2 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.5.1	Verify each shutdown bank is within the limits specified in the COLR.	12 hours

3.1 REACTIVITY CONTROL SYSTEMS

3.1.6 Control Bank Insertion Limits

LCO 3.1.6 Control banks shall be within the insertion, sequence, and overlap limits specified in the COLR.

APPLICABILITY: MODE 1,
MODE 2 with $k_{eff} \geq 1.0$.

------------------------------NOTE------------------------------
This LCO is not applicable while performing SR 3.1.4.2.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Control bank insertion limits not met.	A.1.1 Verify SDM is within the limits specified in the COLR.	1 hour
	<u>OR</u>	
	A.1.2 Initiate boration to restore SDM to within limit.	1 hour
	<u>AND</u>	
	A.2 Restore control bank(s) to within limits.	2 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Control bank sequence or overlap limits not met.	B.1.1 Verify SDM is within the limits specified in the COLR. OR B.1.2 Initiate boration to restore SDM to within limit. AND B.2 Restore control bank sequence and overlap to within limits.	1 hour 1 hour 2 hours
C. Required Action and associated Completion Time not met.	C.1 Be in MODE 3.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.6.1	Verify estimated critical control bank position is within the limits specified in the COLR.	Within 4 hours prior to achieving criticality

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.1.6.2	Verify each control bank insertion is within the limits specified in the COLR.	12 hours
SR 3.1.6.3	Verify sequence and overlap limits specified in the COLR are met for control banks not fully withdrawn from the core.	12 hours

3.1 REACTIVITY CONTROL SYSTEMS

3.1.7 Rod Position Indication

LCO 3.1.7 The Individual Rod Position Indication (IRPI) System and the Demand Position Indication System shall be OPERABLE.

APPLICABILITY: MODES 1 and 2.

ACTIONS

------------------------------------NOTE------------------------------------
Separate Condition entry is allowed for each inoperable rod position indicator per group and each demand position indicator per bank.

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One IRPI per group inoperable for one or more groups.	A.1	Verify the position of the rods with inoperable position indicators by using movable incore detectors.	8 hours AND Once per 24 hours thereafter
	OR		
	A.2	Reduce THERMAL POWER to ≤ 50% RTP.	8 hours

(continued)

ACTIONS (condtinued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. One or more rods with inoperable position indicators have been moved in excess of 24 steps in one direction since the last determination of the rod's position.	B.1	Verify the position of the rods with inoperable position indicators by using movable incore detectors.	8 hours
	<u>OR</u>		
	B.2	Reduce THERMAL POWER to ≤ 50% RTP.	8 hours
C. One demand position indicator per bank inoperable for one or more banks.	C.1.1	Verify by administrative means all IRPIs for the affected banks are OPERABLE.	Once per 8 hours
	<u>AND</u>		
	C.1.2	Verify the most withdrawn rod and the least withdrawn rod of the affected banks are ≤ 12 steps apart when > 85% RTP and ≤ 18 steps apart when ≤ 85% RTP.	Once per 8 hours
	<u>OR</u>		
	C.2	Reduce THERMAL POWER to ≤ 50% RTP.	8 hours

(continued)

ACTIONS (condtinued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Required Action and associated Completion Time not met.	D.1 Be in MODE 3.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.7.1	Verify each IRPI agrees within 12 steps of the group demand position for the full indicated range of rod travel.	Prior to reactor crititcality after each removal of the reactor vessel head

3.1 REACTIVITY CONTROL SYSTEMS

3.1.8 PHYSICS TESTS Exceptions – MODE 2

LCO 3.1.8 During the performance of PHYSICS TESTS, the requirements of

LCO 3.1.3, "Moderator Temperature Coefficient (MTC)";
LCO 3.1.4, "Rod Group Alignment Limits";
LCO 3.1.5, "Shutdown Bank Insertion Limits";
LCO 3.1.6, "Control Bank Insertion Limits"; and
LCO 3.4.2, "RCS Minimum Temperature for Criticality"

may be suspended, provided:

a. RCS lowest loop average temperature is ≥ 540°F; and

b. SDM is within the limits specified in the COLR; and

c. THERMAL POWER IS ≤ 5% RTP.

APPLICABILITY: MODE 2 during PHYSICS TESTS.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. SDM not within limit.	A.1 Initiate boration to restore SDM to within limit. AND A.2 Suspend PHYSICS TESTS exceptions.	15 minutes 1 hour
B. THERMAL POWER not within limit.	B.1 Open reactor trip breakers.	Immediately

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. RCS lowest loop average temperature not within limit.	C.1 Restore RCS lowest loop average temperature to within limit.	15 minutes
D. Required Action and associated Completion Time of Condition C not met.	D.1 Be in MODE 3.	15 minutes

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.1.8.1	Perform a CHANNEL OPERATIONAL TEST on power range and intermediate range channels per SR 3.3.1.7, SR 3.3.1.8, and Table 3.3.1-1.	Prior to initiation of PHYSICS TESTS
SR 3.1.8.2	Verify the RCS lowest loop average temperature is ≥ 540°F.	30 minutes
SR 3.1.8.3	Verify THERMAL POWER is ≤ 5% RTP.	30 minutes
SR 3.1.8.4	Verify SDM is within the limits specified in the COLR.	24 hours

3.2 POWER DISTRIBUTION LIMITS

3.2.1 Heat Flux Hot Channel Factor ($F_Q(Z)$)

LCO 3.2.1 $F_Q(Z)$ shall be within the limits specified in the COLR.

APPLICABILITY: MODE 1.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. $F_Q(Z)$ not within limit.	A.1 Reduce THERMAL POWER $\geq$ 1% RTP for each 1% $F_Q(Z)$ exceeds limit.	15 minutes
	<u>AND</u>	
	A.2 Reduce Power Range Neutron Flux – High trip setpoints $\geq$ 1% for each 1% $F_Q(Z)$ exceeds limit.	72 hours
	<u>AND</u>	
	A.3 Perform SR 3.2.1.1.	Prior to increasing THERMAL POWER above the limit of Required Action A.1
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 2.	6 hours

SURVEILLANCE REQUIREMENTS

------------------------------------NOTE------------------------------------
During power escalation at the beginning of each cycle, THERMAL POWER may be increased until an equilibrium power level has been achieved, at which a power distribution map is obtained.

SURVEILLANCE		FREQUENCY
SR 3.2.1.1	Verify $F_Q(Z)$ is within limit.	Once after each refueling prior to THERMAL POWER exceeding 75% RTP <u>AND</u> Once within 12 hours after achieving equilibrium conditions after exceeding, by ≥ 10% RTP, the THERMAL POWER at which $F_Q(Z)$ was last verified <u>AND</u> 31 EFPD thereafter

3.2 POWER DISTRIBUTION LIMITS

3.2.2 Nuclear Enthalpy Rise Hot Channel Factor ($F^N_{\Delta H}$)

LCO 3.2.2 $F^N_{\Delta H}$ shall be within the limits specified in the COLR.

APPLICABILITY: MODE 1.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. ---------NOTE--------- Required Actions A.2 and A.3 must be completed whenever Condition A is entered. --------------------- $F^N_{\Delta H}$ not within limit.	A.1.1 Restore $F^N_{\Delta H}$ to within limit.	4 hours
	<u>OR</u>	
	A.1.2.1 Reduce THERMAL POWER to < 50% RTP.	4 hours
	<u>AND</u>	
	A.1.2.2 Reduce Power Range Neutron Flux–High trip setpoints to ≤ 55% RTP.	72 hours
	<u>AND</u>	
	A.2 Perform SR 3.2.2.1.	24 hours
	<u>AND</u>	
		(continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.3 --------NOTE-------- THERMAL POWER does not have to be reduced to comply with this Required Action. -------------------- Perform SR 3.2.2.1.	Prior to THERMAL POWER exceeding 50% RTP AND Prior to THERMAL POWER exceeding 75% RTP AND 24 hours after THERMAL POWER reaching ≥ 95% RTP
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 2.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.2.2.1	Verify $F^N_{\Delta H}$ is within limits specified in the COLR.	Once after each refueling prior to THERMAL POWER exceeding 75% RTP <u>AND</u> 31 EFPD thereafter

3.2 POWER DISTRIBUTION LIMITS

3.2.3 AXIAL FLUX DIFFERENCE (AFD) (Constant Axial Offset Control (CAOC) Methodology)

LCO 3.2.3 The AFD:

a. Shall be maintained within the target band about the target flux difference. The target band is specified in the COLR.

b. May deviate outside the target band with THERMAL POWER < 90% RTP but ≥ 50% RTP, provided AFD is within the acceptable operation limits and cumulative penalty deviation time is ≤ 1 hour during the previous 24 hours. The acceptable operation limits are specified in the COLR.

c. May deviate outside the target band with THERMAL POWER < 50% RTP.

---------------------------- NOTES ----------------------------

1. The AFD shall be considered outside the target band when two or more OPERABLE excore channels indicate AFD to be outside the target band.

2. With Thermal Power ≥ 50% RTP, penalty deviation time shall be accumulated on the basis of a 1 minute penalty deviation for each 1 minute of power operation with AFD outside the target band.

3. With Thermal Power < 50% RTP and > 15% RTP, penalty deviation time shall be accumulated on the basis of a 0.5 minute penalty deviation for each 1 minute of power operation with AFD outside the target band.

4. A total of 16 hours of operation may be accumulated with AFD outside the target band without penalty deviation time during surveillance of power range channels in accordance with SR 3.3.1.6, provided AFD is maintained within acceptable operation limits.

APPLICABILITY: MODE 1 with THERMAL POWER > 15% RTP.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. THERMAL POWER ≥ 90% RTP. AND AFD not within the target band.	A.1	Restore AFD to within target band.	15 minutes
B. Required Action and associated Completion Time of Condition A not met.	B.1	Reduce THERMAL POWER to < 90% RTP.	15 minutes
C. ---------NOTE--------- Required Action C.1 must be completed whenever Condition C is entered. --------------------- THERMAL POWER < 90% and ≥ 50% RTP with cumulative penalty deviation time > 1 hour during the previous 24 hours. OR THERMAL POWER < 90% and ≥ 50% RTP with AFD not within the acceptable operation limits.	C.1	Reduce THERMAL POWER to < 50% RTP.	30 minutes

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.2.3.1	Verify AFD is within target band for each OPERABLE excore channel.	7 days
SR 3.2.3.2	------------------NOTE------------------ Assume logged values of AFD exist during the preceding time interval. --- Verify AFD is within target band and log AFD for each OPERABLE excore channel.	-----NOTE------ Only required to be performed if AFD monitor alarm is inoperable -------------- Once within 15 minutes and every 15 minutes thereafter when THERMAL POWER ≥ 90% RTP <u>AND</u> Once within 1 hour and every 1 hour thereafter when THERMAL POWER < 90% RTP

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.2.3.3	Update target flux difference of each OPERABLE excore channel by: a. Determining the target flux difference in accordance with SR 3.2.3.4, or b. Using linear interpolation between the most recently measured value, and either the predicted value for the end of cycle or 0% AFD.	Once within 31 EFPD after each refueling AND 31 EFPD thereafter
SR 3.2.3.4	------------------NOTE------------------ The initial target flux difference after each refueling may be determined from design predictions. --- Determine, by measurement, the target flux difference of each OPERABLE excore channel.	Once within 31 EFPD after each refueling AND 92 EFPD thereafter

3.2 POWER DISTRIBUTION LIMITS

3.2.4 QUADRANT POWER TILT RATIO (QPTR)

LCO 3.2.4 The QPTR shall be $\leq$ 1.02.

APPLICABILITY: MODE 1 with THERMAL POWER > 50% RTP.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
---------NOTE--------- Required Actions A.4, A.5 and A.6 must be completed whenever Condition A is entered. ---------------------	A.1 Reduce THERMAL POWER $\geq$ 3% from RTP for each 1% of QPTR > 1.00.	2 hours
	<u>AND</u>	
A. QPTR not within limit.	A.2 Determine QPTR and reduce THERMAL POWER $\geq$ 3% from RTP for each 1% of QPTR > 1.00.	Once per 12 hours
	<u>AND</u>	
	A.3 Perform SR 3.2.1.1 and SR 3.2.2.1.	24 hours <u>AND</u> Once per 7 days thereafter
	<u>AND</u>	
	A.4 Re-evaluate safety analyses and confirm results remain valid for duration of operation under this condition.	Prior to increasing THERMAL POWER above the limit of Required Action A.1
	<u>AND</u>	
		(continued)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. (continued)	A.5	--------NOTE--------- Perform Required Action A.5 only after Required Action A.4 is completed. ---------------------	
		Calibrate excore detectors to show 1.00 QPTR.	Prior to increasing THERMAL POWER above the limit of Required Action A.1
	AND		
	A.6	--------NOTE--------- Perform Required Action A.6 only after Required Action A.5 is completed. ---------------------	
		Perform SR 3.2.1.1 and SR 3.2.2.1.	Within 24 hours after reaching RTP OR Within 48 hours after increasing THERMAL POWER above the limit of Required Action A.1
B. Required Action and associated Completion Time not met.	B.1	Reduce THERMAL POWER to ≤ 50% RTP.	4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.2.4.1	-----------------NOTES--------------------- 1. With input from one Power Range Neutron Flux channel inoperable and THERMAL POWER < 75% RTP, the remaining three power range channels can be used for calculating QPTR. 2. SR 3.2.4.2 may be performed in lieu of this Surveillance. --- Verify QPTR is within limit by calculation.	7 days
SR 3.2.4.2	------------------NOTE-------------------- Not required to be performed until 24 hours after input from one or more Power Range Neutron Flux channels are inoperable with THERMAL POWER ≥ 75% RTP. --- Verify QPTR is within limit using the movable incore detectors.	24 hours

3.3 INSTRUMENTATION

3.3.1 Reactor Protection System (RPS) Instrumentation

LCO 3.3.1 The RPS instrumentation for each Function in Table 3.3.1-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.1-1.

ACTIONS

------------------------------------NOTES------------------------------------

1. Separate Condition entry is allowed for each Function.
2. When a channel or train is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 8 hours provided the associated Function maintains RPS trip capability.

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or more Functions with one or more required channels or trains inoperable.	A.1	Enter the Condition referenced in Table 3.3.1-1 for the channel(s) or train (s).	Immediately
B. One Manual Reactor Trip channel inoperable.	B.1	Restore channel to OPERABLE status.	48 hours
	<u>OR</u>		
	B.2	Be in MODE 3.	54 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One channel or train inoperable.	C.1 Restore channel or train to OPERABLE status.	48 hours
	<u>OR</u>	
	C.2.1 Initiate action to fully insert all rods.	48 hours
	<u>AND</u>	
	C.2.2 Place the Rod Control System in a condition incapable of rod withdrawal.	49 hours
D. One Power Range Neutron Flux – High channel inoperable.	-------------NOTE------------- The inoperable channel may be bypassed for up to 8 hours for surveillance testing and setpoint adjustment of other channels. ------------------------------	
	D.1.1 Place channel in trip.	6 hours
	<u>AND</u>	
	D.1.2 Reduce THERMAL POWER to ≤ 75% RTP.	24 hours
	<u>OR</u>	
	D.2.1 Place channel in trip.	6 hours
	<u>AND</u>	

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. (continued)	---------------NOTE--------------- Only required to be performed when the Power Range Neutron Flux input to QPTR is inoperable. -------------------------------	
	D.2.2 Perform SR 3.2.4.2.	Once per 24 hours
	OR	
	D.3 Be in MODE 3.	12 hours
E. One channel inoperable.	-------------NOTE------------- The inoperable channel may be bypassed for up to 8 hours for surveillance testing of other channels. -------------------------------	
	E.1 Place channel in trip.	6 hours
	OR	
	E.2 Be in MODE 3.	12 hours
F. Required Intermediate Range Neutron Flux channel inoperable.	F.1 Suspend operations involving positive reactivity additions.	Immediately
	AND	
	F.2 Reduce THERMAL POWER to < P-6.	2 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
G. Required Source Range Neutron Flux channel inoperable.	G.1 Open Reactor Trip Breakers (RTBs).	Immediately
H. One channel inoperable.	-------------NOTE------------- The inoperable channel may be bypassed for up to 8 hours for surveillance testing of other channels. ------------------------------	
	H.1 Place channel in trip.	6 hours
	<u>OR</u>	
	H.2 Reduce THERMAL POWER to < P-7.	12 hours
I. One Reactor Coolant Pump Breaker Position channel inoperable.	------------NOTE------------- The inoperable channel may be bypassed for up to 8 hours for surveillance testing of other channels. ------------------------------	
	I.1 Restore channel to OPERABLE status.	6 hours
	<u>OR</u>	
	I.2 Reduce THERMAL POWER to < P-8.	10 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
J. One Turbine Trip channel inoperable.	-------------NOTE------------- The inoperable channel may be bypassed for up to 8 hours for surveillance testing of other channels. ------------------------------	
	J.1 Place channel in trip.	6 hours
	OR	
	J.2 Reduce THERMAL POWER to < P-7.	12 hours
K. One train inoperable.	------------NOTE------------- One train may be bypassed for up to 8 hours for surveillance testing provided the other train is OPERABLE. ------------------------------	
	K.1 Restore train to OPERABLE status.	6 hours
	OR	
	K.2 Be in MODE 3.	12 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
L. One RTB train inoperable.	-------------NOTES------------ 1. One train may be bypassed for up to 2 hours for testing, provided the other train is OPERABLE. 2. One RTB may be bypassed for up to 2 hours for maintenance on undervoltage or shunt trip mechanisms, provided the other train is OPERABLE. ------------------------------	
	L.1 Restore train to OPERABLE status.	1 hour
	<u>OR</u>	
	L.2 Be in MODE 3.	7 hours
M. One or more channels inoperable.	M.1 Verify interlock is in required state for existing unit conditions.	1 hour
	<u>OR</u>	
	M.2 Be in MODE 3.	7 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
N. One or more channels inoperable.	N.1	Verify interlock is in required state for existing unit conditions.	1 hour
	OR		
	N.2	Be in MODE 2.	7 hours
O. One trip mechanism inoperable for one RTB.	O.1	Restore inoperable trip mechanism to OPERABLE status.	48 hours
	OR		
	O.2.	Be in MODE 3.	54 hours

SURVEILLANCE REQUIREMENTS

-----NOTE-----
Refer to Table 3.3.1-1 to determine which SRs apply for each RPS Function.

SURVEILLANCE		FREQUENCY
SR 3.3.1.1	Perform CHANNEL CHECK.	12 hours
SR 3.3.1.2	-----NOTES----- 1. Adjust NIS channel if absolute difference is > 2%. 2. Not required to be performed until 24 hours after THERMAL POWER is ≥ 15% RTP. ---------- Compare results of calorimetric heat balance calculation to Nuclear Instrumentation System (NIS) channel output.	24 hours
SR 3.3.1.3	-----NOTES----- 1. Adjust NIS channel if absolute difference is ≥ 3%. 2. Only required to be performed when THERMAL POWER is > 90% RTP. ---------- Compare results of the incore detector measurements to NIS AFD.	31 effective full power days (EFPD)

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.4	-------------------NOTE-------------------- This Surveillance must be performed on the reactor trip bypass breaker prior to placing the bypass breaker in service. -- Perform TADOT.	31 days on a STAGGERED TEST BASIS
SR 3.3.1.5	Perform ACTUATION LOGIC TEST.	31 days on a STAGGERED TEST BASIS
SR 3.3.1.6	-------------------NOTE-------------------- Only required to be performed when THERMAL POWER is > 90% RTP. -- Calibrate excore channels to agree with incore detector measurements.	31 EFPD
SR 3.3.1.7	------------------NOTE--------------------- Not required to be performed for source range instrumentation prior to entering MODE 3 from MODE 2 until 8 hours after entry into MODE 3. -- Perform COT.	92 days

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.8	------------------NOTE------------------ This Surveillance shall include verification that interlocks P-6 and P-10 are in their required state for existing unit conditions. -- Perform COT.	------NOTE------ Only required when not performed within previous 92 days --------------- Prior to reactor startup AND Sixteen hours after reducing power below P-10 for power and intermediate instrumentation AND Eight hours after reducing power below P-6 for source range instrumentation AND Every 92 days thereafter

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.9	-------------------NOTE------------------- Verification of setpoint is not required. -- Perform TADOT.	92 days
SR 3.3.1.10	-------------------NOTE------------------- This Surveillance shall include verification that the time constants are adjusted to the prescribed values. -- Perform CHANNEL CALIBRATION.	24 months <u>AND</u> 18 months for Function 11
SR 3.3.1.11	-------------------NOTE------------------- Neutron detectors are excluded from CHANNEL CALIBRATION. -- Perform CHANNEL CALIBRATION.	24 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.12	-------------------NOTE-------------------- This Surveillance shall include verification that the electronic dynamic compensation time constants are set at the required values. -- Perform CHANNEL CALIBRATION.	24 months
SR 3.3.1.13	Perform COT.	24 months
SR 3.3.1.14	-------------------NOTE-------------------- Verification of setpoint is not required. -- Perform TADOT.	24 months
SR 3.3.1.15	-------------------NOTE-------------------- Verification of setpoint is not required. -- Perform TADOT.	24 months

Table 3.3.1-1 (page 1 of 8)
Reactor Protection System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Manual Reactor Trip	1,2	2	B	SR 3.3.1.14	NA
	3(a), 4(a), 5(a)	2	C	SR 3.3.1.14	NA
2. Power Range Neutron Flux					
a. High	1,2	4	D	SR 3.3.1.1 SR 3.3.1.2 SR 3.3.1.7 SR 3.3.1.11	≤ 109% RTP
b. Low	1(b),2	4	E	SR 3.3.1.1 SR 3.3.1.8 SR 3.3.1.11	≤ 25% RTP
3. Intermediate Range Neutron Flux	1(b), 2(c)	1	F	SR 3.3.1.1 SR 3.3.1.8 SR 3.3.1.11	NA

(continued)

(a) With Rod Control System capable of rod withdrawal and one or more rods not fully inserted.

(b) Below the P-10 (Power Range Neutron Flux) interlocks.

(c) Above the P-6 (Intermediate Range Neutron Flux) interlocks.

Table 3.3.1-1 (page 2 of 8)
Reactor Protection System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
4. Source Range Neutron Flux	$2^{(d)}$	1	G	SR 3.3.1.1 SR 3.3.1.8 SR 3.3.1.11	NA
	$3^{(a)}$, $4^{(a)}$, $5^{(a)}$	1	G	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.11	NA
5. Overtemperature ΔT	1,2	4	E	SR 3.3.1.1 SR 3.3.1.3 SR 3.3.1.6 SR 3.3.1.7 SR 3.3.1.12	Refer to Note 1
6. Overpower ΔT	1,2	4	E	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.12	Refer to Note 2

(continued)

(a) With Rod Control System capable of rod withdrawal and one or more rods not fully inserted.

(d) Below the P-6 (Intermediate Range Neutron Flux) interlocks.

Table 3.3.1-1 (page 3 of 8)
Reactor Protection System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
7. Pressurizer Pressure					
a. Low	1(e)	4	H	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10	≥ 1749 psig
b. High	1,2	3	E	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10	≤ 2408.24 psig
8. Pressurizer Water Level – High	1(e)	3	H	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10	≤ 97.47%
9. Reactor Coolant Flow – Low	1(e)	3 per loop(j)	H	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10	≥ 89%

(continued)

(e) Above the P-7 (Low Power Reactor Trips Block) interlock.

(j) Separate condition entry is allowed for each loop.

Table 3.3.1-1 (page 4 of 8)
Reactor Protection System Instrumentation

	FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
10.	Reactor Coolant Pump (RCP) Breaker Position					
	a. Single Loop	$1^{(f)}$	1 per RCP	I	SR 3.3.1.14	NA
	b. Two Loops	$1^{(g)}$	1 per RCP	H	SR 3.3.1.14	NA
11.	Undervoltage RCPs (6.9 kV bus)	$1^{(e)}$	1 per bus	H	SR 3.3.1.9 SR 3.3.1.10	≥ 68.37% V
12.	Underfrequency RCPs (6.9 kV bus)	$1^{(e)}$	1 per bus	H	SR 3.3.1.9 SR 3.3.1.10	≥ 57.22 Hz
13.	Steam Generator (SG) Water Level - Low Low	1.2	3 per $SG^{(k)}$	E	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10	≥ 3.54%
14.	SG Water Level - Low	1.2	2 per $SG^{(k)}$	E	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10	NA
	Coincident with Steam Flow/Feedwater Flow Mismatch	1.2	2 per $SG^{(k)}$	E	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10	NA

(continued)

(e) Above the P-7 (Low Power Reactor Trips Block) interlock.

(f) Above the P-8 (Power Range Neutron Flux) interlock.

(g) Above the P-7 (Low Power Reactor Trips Block) interlock and below the P-8 (Power Range Neutron Flux) interlock.

(k) Separate condition entry is allowed for each SG.

Table 3.3.1-1 (page 5 of 8)
Reactor Protection System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
15. Turbine Trip-Auto-Stop Oil Pressure	1(h)	3	J	SR 3.3.1.10 SR 3.3.1.15	NA
16. Safety Injection (SI) Input from Engineered Safety Feature Actuation System (ESFAS)	1,2	2 trains	K	SR 3.3.1.14	NA
17. Reactor Trip System Interlocks					
a. Intermediate Range Neutron Flux, P-6	2(d)	2 trains	M	SR 3.3.1.11 SR 3.3.1.13	NA
b. Low Power Reactor Trips Block, P-7	1	2 trains	N	SR 3.3.1.11 SR 3.3.1.13	NA
c. Power Range Neutron Flux, P-8	1	4	N	SR 3.3.1.11 SR 3.3.1.13	≤ 50.0% RTP
d. Power Range Neutron Flux, P-10	1,2	4	M	SR 3.3.1.11 SR 3.3.1.13	< 10% RTP
e. Turbine First Stage Pressure, P-7 Input	1	2	N	SR 3.3.1.1 SR 3.3.1.10 SR 3.3.1.13	< 10% turbine power

(continued)

(d) Below the P-6 (Intermediate Range Neutron Flux) interlocks.

(h) Above the P-7 (Low Power Reactor Trips Block) interlock except during turbine overspeed trip testing.

Table 3.3.1-1 (page 6 of 8)
Reactor Protection System Instrumentation

	FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
18.	Reactor Trip Breakers(RTBs)[i]	1,2	2 trains	L	SR 3.3.1.4	NA
		3[a], 4[a], 5[a]	2 trains	C	SR 3.3.1.4	NA
19.	Reactor Trip Breaker Undervoltage and Shunt Trip Mechanisms	1,2	1 each per RTB	O	SR 3.3.1.4	NA
		3[a], 4[a], 5[a]	1 each per RTB	C	SR 3.3.1.4	NA
20.	Automatic Trip Logic	1,2	2 trains	K	SR 3.3.1.5	NA
		3[a], 4[a], 5[a]	2 trains	C	SR 3.3.1.5	NA

(a) With Rod Control System capable of rod withdrawal and one or more rods not fully inserted.

(i) Including any reactor trip bypass breakers that are racked in and closed for bypassing an RTB.

Table 3.3.1-1 (page 7 of 8)
Reactor Protection System Instrumentation

Note 1: Overtemperature ΔT

The Overtemperature ΔT Function Allowable Value shall not exceed the following:

$$\Delta T \leq \Delta T_o \, [K_1 - K_2 \, [(1 + \tau_1 s)/(1 + \tau_2 s)] \, (T_{avg} - T') + K_3 \, (P - P') - f(\Delta I)]$$

Where: $K_1 \leq 1.285$ $\quad K_2 = 0.0273$ $\quad K_3 = 0.0013$

$\tau_1 \geq 25$ seconds $\quad \tau_2 \leq 3$ seconds

ΔT_o ≤ Measured full power ΔT for the channel being calibrated, °F.

T_{avg} = Average Temperature for the channel being calibrated, °F (input from instrument racks)

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

T' = Measured full power T_{avg} for the channel being calibrated, °F

P = Pressurizer pressure, psig (input from instrument racks)

P' = 2235 psig (i.e., nominal pressurizer pressure at rated power)

K_1 is a constant which defines the overtemperature ΔT trip margin during steady state operation if the temperature, pressure, and $f(\Delta I)$ terms are zero.

K_2 is a constant which defines the dependence of the overtemperature ΔT setpoint to T_{avg}.

K_3 is a constant which defines the dependence of the overtemperature ΔT setpoint to pressurizer pressure.

τ dynamic compensation time constants

ΔI = $q_t - q_b$, where q_t and q_b are the percent power in the top and bottom halves of the core respectively, and $q_t + q_b$ is total core power in percent of RTP.

$f(\Delta I)$ = a function of the indicated difference between top and bottom detectors of the power-range nuclear ion chambers; with gains to be selected based on measured instrument response during plant startup tests, where q_t and q_b are defined above such that:

(a) for $q_t - q_b$ between -15.75% and +6.9%, $f(\Delta I)=0$.

(b) for each percent that the magnitude of $q_t - q_b$ exceeds +6.9%, the ΔT trip setpoint shall be automatically reduced by an equivalent of 3.333% of RTP.

(c) or each percent that the magnitude of $q_t - q_b$ is more negative than -15.75%, the ΔT trip setpoint shall be automatically reduced by an equivalent of 4.000% of RTP.

Table 3.3.1-1 (page 8 of 8)
Reactor Protection System Instrumentation

Note 2: Overpower ΔT

The Overpower ΔT Function Allowable Value shall not exceed the following:

$$\Delta T \leq \Delta T_o (K_4 - K_5 (dTavg/dt) - K_6(T_{avg} - T'))$$

Where:

$K_4 \leq 1.154$

$K_5 =$ 0 for decreasing average temperature; and
$\geq$ 0.175 sec/°F for increasing average temperature

$K_6 =$ 0 for $T \leq T'$; and
$\geq$ 0.00134 for $T > T'$

$\Delta T_o \leq$ measured full power ΔT for the channel being calibrated, °F

$T_{avg} =$ measured average temperature for the channel being calibrated, °F (input from instrument racks)

$T' =$ measured full power T_{avg} for the channel being calibrated, °F (can be set no higher than 570.3 °F)

$s =$ Laplace transform operator, seconds

K_4 is a constant which defines the overpower ΔT trip margin during steady state operation if the temperature term is zero.

K_5 is a constant determined by dynamic considerations to compensate for piping delays from the core to the loop temperature detectors; it represents the combination of the equipment static gain setting and the time constant setting.

K_6 is a constant which defines the dependence of the overpower ΔT setpoint to T_{avg}.

dTavg/dt is the rate of change of T_{avg}

3.3 INSTRUMENTATION

3.3.2 Engineered Safety Feature Actuation System (ESFAS) Instrumentation

LCO 3.3.2 The ESFAS instrumentation for each Function in Table 3.3.2-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.2-1.

ACTIONS

------------------------------------NOTES------------------------------------

1. Separate Condition entry is allowed for each Function.

2. When a channel or train is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 8 hours provided the associated Function maintains ESFAS trip capability.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Functions with one or more required channels or trains inoperable.	A.1 Enter the Condition referenced in Table 3.3.2-1 for the channel(s) or train(s).	Immediately
B. One channel or train inoperable.	B.1 Restore channel or train to OPERABLE status.	48 hours
	<u>OR</u>	
	B.2.1 Be in MODE 3.	54 hours
	<u>AND</u>	
	B.2.2 Be in MODE 5.	84 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One train inoperable.	C.1 ---------NOTE--------- One train may be bypassed for up to 8 hours for surveillance testing provided the other train is OPERABLE. ---------------------	
	Restore train to OPERABLE status.	6 hours
	OR	
	C.2.1 Be in MODE 3.	12 hours
	AND	
	C.2.2 Be in MODE 5.	42 hours
D. One channel inoperable.	D.1 ---------NOTE--------- The inoperable channel may be bypassed for up to 8 hours for surveillance testing of other channels. ---------------------	
	Place channel in trip.	6 hours
	OR	
	D.2.1 Be in MODE 3.	12 hours
	AND	
	D.2.2 Be in MODE 4.	18 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
E. One Containment Pressure channel inoperable in one or both sets of three.	E.1	---------NOTE--------- One additional channel may be bypassed for up to 8 hours for surveillance testing. --------------------- Place channel in trip.	6 hours
	OR		
	E.2.1	Be in MODE 3.	12 hours
	AND		
	E.2.2	Be in MODE 4.	18 hours
F. One channel or train inoperable.	F.1	Restore channel or train to OPERABLE status.	48 hours
	OR		
	F.2.1	Be in MODE 3.	54 hours
	AND		
	F.2.2	Be in MODE 4.	60 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
G. One train inoperable.	G.1	---------NOTE--------- One train may be bypassed for up to 8 hours for surveillance testing provided the other train is OPERABLE. --------------------- Restore train to OPERABLE status.	6 hours
	<u>OR</u>		
	G.2.1	Be in MODE 3.	12 hours
	<u>AND</u>		
	G.2.2	Be in MODE 4.	18 hours
H. One train inoperable.	H.1	---------NOTE--------- One train may be bypassed for up to 8 hours for surveillance testing provided the other train is OPERABLE. --------------------- Restore train to OPERABLE status.	6 hours
	<u>OR</u>		
	H.2	Be in MODE 3.	12 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
I. Main Feedwater Pump trip channel(s) inoperable.	I.1	Verify one channel associated with an operating MBFP is OPERABLE.	Immediately
	<u>AND</u>		
	I.2	Restore one channel associated with each operating MBFP to OPERABLE status.	48 hours
J. Required Action and associated Completion Time of Condition I not met.	J.1	Be in MODE 3.	6 hours
K. One or more channels inoperable.	K.1	Verify interlock is in required state for existing unit condition.	1 hour
	<u>OR</u>		
	K.2.1	Be in MODE 3.	7 hours
	<u>AND</u>		
	K.2.2	Be in MODE 4.	13 hours

SURVEILLANCE REQUIREMENTS

------------------------------------NOTE------------------------------------
Refer to Table 3.3.2-1 to determine which SRs apply for each ESFAS Function.

SURVEILLANCE		FREQUENCY
SR 3.3.2.1	Perform CHANNEL CHECK.	12 hours
SR 3.3.2.2	Perform ACTUATION LOGIC TEST.	31 days on a STAGGERED TEST BASIS
SR 3.3.2.3	Perform MASTER RELAY TEST.	31 days on a STAGGERED TEST BASIS
SR 3.3.2.4	Perform COT.	92 days
SR 3.3.2.5	Perform SLAVE RELAY TEST.	24 months
SR 3.3.2.6	-------------------NOTE------------------- Verification of setpoint not required for manual initiation functions. -- Perform TADOT.	24 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.2.7	------------------NOTE------------------ This Surveillance shall include verification that the time constants are adjusted to the prescribed values. -- Perform CHANNEL CALIBRATION.	24 months

Table 3.3.2-1 (page 1 of 6)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Safety Injection					
a. Manual Initiation	1,2,3,4	2	B	SR 3.3.2.6	NA
b. Automatic Actuation Logic and Actuation Relays	1,2,3,4[(a)]	2 trains	C	SR 3.3.2.2 SR 3.3.2.3 SR 3.3.2.5	NA
c. Containment Pressure-Hi	1,2,3	3	D	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	≤ 4.80 psig
d. Pressurizer Pressure-Low	1,2,3[(b)]	3	D	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	≥ 1684.64 psig
e. High Differential Pressure Between Steam Lines	1,2,3	3 per steam line[(h)]	D	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	≤ 208 psid
f. High Steam Flow in Two Steam Lines	1,2[(d)],3[(d)]	2 per steam line[(h)]	D	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	(c)
Coincident with T_{avg} - Low	1,2[(d)],3[(d)]	1 per loop[(i)]	D	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	≥ 535.6°F

(continued)

(a) Only as needed to support Manual initiation capability when in MODE 4.

(b) Above the Pressurizer Pressure interlock.

(c) Less than or equal to turbine first stage pressure corresponding to 54.4% full steam flow below 20% load, and increasing linearly from 54.4% full steam flow at 20% load to 110% full steam flow at 100% load, and corresponding to 110% full steam flow above 100% load. Time delay for SI ≤ 6 seconds.

(d) Except when all MSIVs are closed.

(h) Separate Condition entry is allowed for each steam line.

(i) Separate Condition entry is allowed for each loop.

Table 3.3.2-1 (page 2 of 6)
Engineered Safety Feature Actuation System Instrumentation

	FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1.	Safety Injection (continued)					
	g. High Steam Flow in Two Steam Lines	1,2(d),3(d)	2 per steam line(h)	D	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	(c)
	Coincident with Steam Line Pressure-Low	1,2(d),3(d)	1 per steam line(h)	D	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	≥ 476.0 psig
2.	Containment Spray					
	a. Manual Initiation	1,2,3,4	2 per train, 2 trains	B	SR 3.3.2.6	NA
	b. Automatic Actuation Logic and Actuation Relays	1,2,3,4(a)	2 trains	C	SR 3.3.2.2 SR 3.3.2.3 SR 3.3.2.5	NA
	c. Containment Pressure (Hi-Hi)	1,2,3	2 sets of 3	E	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	≤ 24.3 psig

(continued)

(a) Only as needed to support Manual initiation capability when in MODE 4.

(c) Less than or equal to turbine first stage pressure corresponding to 54.4% full steam flow below 20% load, and increasing linearly from 54.4% full steam flow at 20% load to 110% full steam flow at 100% load, and corresponding to 110% full steam flow above 100% load. Time delay for SI ≤ 6 seconds.

(d) Except when all MSIVs are closed.

(h) Separate Condition entry is allowed for each steam line.

Table 3.3.2-1 (page 3 of 6)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
3. Containment Isolation					
a. Phase A Isolation					
(1) Manual Initiation	1,2,3,4	2	B	SR 3.3.2.6	NA
(2) Automatic Actuation Logic and Actuation Relays	1,2,3,4(a)	2 trains	C	SR 3.3.2.2 SR 3.3.2.3 SR 3.3.2.5	NA
(3) Safety Injection	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.				
b. Phase B Isolation					
(1) Manual Initiation	1,2,3,4	2	B	SR 3.3.2.6	NA
(2) Automatic Actuation Logic and Actuation Relays	1,2,3,4(a)	2 trains	C	SR 3.3.2.2 SR 3.3.2.3 SR 3.3.2.5	NA
(3) Containment Pressure (Hi-Hi)	1,2,3	2 sets of three	E	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	≤ 24.3 psig

(continued)

(a) Only as needed to support Manual initiation capability when in MODE 4.

Table 3.3.2-1 (page 4 of 6)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
4. Steam Line Isolation					
a. Manual Initiation	1,2(d),3(d)	2 per steam line	F	SR 3.3.2.6	NA
b. Automatic Actuation Logic and Actuation Relays	1,2(d),3(d)	2 trains	G	SR 3.3.2.2 SR 3.3.2.3 SR 3.3.2.5	NA
c. Containment Pressure (Hi-Hi)	1,2(d), 3(d)	2 sets of 3	E	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	≤ 24.3 psig
d. High Steam Flow in Two Steam Lines	1,2(d), 3(d)	2 per steam line(h)	D	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	(c)
Coincident with T_{avg}-Low	1,2(d), 3(d)	1 per loop(i)	D	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	≥ 535.6°F
e. High Steam Flow in Two Steam Lines	1,2(d), 3(d)	2 per steam line (h)	D	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	(c)
Coincident with Steam Line Pressure – Low	1,2(d), 3(d)	1 per steam line (i)	D	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	≥ 476.0 psig

(continued)

(c) Less than or equal to turbine first stage pressure corresponding to 54.4% full steam flow below 20% load, and increasing linearly from 54.4% full steam flow at 20% load to 110% full steam flow at 100% load, and corresponding to 110% full steam flow above 100% load. Time delay for SI ≤ 6 seconds.

(d) Except when all MSIVs are closed.

(h) Separate Condition entry is allowed for each steam line.

(i) Separate Condition entry is allowed for each loop.

Table 3.3.2-1 (page 5 of 6)
Engineered Safety Feature Actuation System Instrumentation

	FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
5.	Feedwater Isolation-Safety Injection	1,2(e)	2 trains	H	SR 3.3.2.2 SR 3.3.2.5	NA
6.	Auxiliary Feedwater					
	a. Automatic Actuation Logic and Actuation Relays	1,2,3	2 trains	G	SR 3.3.2.2 SR 3.3.2.5	NA
	b. SG Water Level-Low Low	1,2,3	3 per SG(j)	D	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	≥ 3.54% NR
	c. Safety Injection (g)	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.				
	d. Loss of Offsite Power (Non SI Blackout Sequence Signal)	1,2,3	1 per bus (2 buses)	F	SR 3.3.2.6 SR 3.3.2.7	≥ 200 V
	e. Trip of Main Boiler Feedwater Pumps	1(f), 2(f)	1 per MBFP	I	SR 3.3.2.6	NA

(continued)

(e) Except when all MBFPDVs, or MBFRVs and associated bypass valves are closed or isolated by a closed manual valve.

(f) Only required for MBFPs that are in operation.

(g) Not required if AFW pump not required to be OPERABLE.

(j) Separate Condition entry is allowed for each SG.

Table 3.3.2-1 (page 6 of 6)
Engineered Safety Feature Actuation System Instrumentation

	FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
7.	ESFAS Interlocks-Pressurizer Pressure	1,2,3	3	K	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	≤ 1998.24 psig

3.3 INSTRUMENTATION

3.3.3 Post Accident Monitoring (PAM) Instrumentation

LCO 3.3.3 The PAM instrumentation for each Function in Table 3.3.3-1 shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

------------------------------------NOTES------------------------------------

1. LCO 3.0.4 is not applicable.

2. Separate Condition entry is allowed for each Function.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Functions with one required channels inoperable.	A.1 Restore one channel to OPERABLE status.	7 days
B. Required Action and associated Completion Time of Condition A not met. <u>OR</u> One or more Functions with two required channels inoperable.	B.1 Enter the Condition referenced in Table 3.3.3-1 for the channel.	Immediately

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. As required by Required Action B.1 and referenced in Table 3.3.3-1.	C.1 Be in MODE 3. AND C.2 Be in MODE 4.	6 hours 12 hours
D. As required by Required Action B.1 and referenced in Table 3.3.3-1.	D.1 Initiate action in accordance with Specification 5.6.7.	Immediately

SURVEILLANCE REQUIREMENTS

------------------------------------NOTE------------------------------------
SR 3.3.3.1 and SR 3.3.3.2 apply to each PAM instrumentation Function in Table 3.3.3-1.

SURVEILLANCE		FREQUENCY
SR 3.3.3.1	Perform CHANNEL CHECK for each required instrumentation channel that is normally energized.	31 days
SR 3.3.3.2	------------------NOTE------------------ Neutron detectors are excluded from CHANNEL CALIBRATION. -- Perform CHANNEL CALIBRATION.	As specified in Table 3.3.3-1

Table 3.3.3-1 (page 1 of 1)
Post Accident Monitoring Instrumentation

	FUNCTION	REQUIRED CHANNELS	CONDITION REFERENCED FROM REQUIRED ACTION B.1	SR 3.3.3.2 FREQUENCY
1.	Neutron Flux	1	D	24 months
2.	RCS Hot Leg Temperature (wide range)	1 loop	C	24 months
3.	RCS Cold Leg Temperature (wide range)	1 loop	C	24 months
4.	RCS Pressure (wide Range)	1	C	24 months
5.	Reactor Vessel Water Level	1	C	24 months
6.	Containment Water Level (Wide Range)	1	C	24 months
7.	Containment Water Level (Recirculation Sump)	1	C	24 months
8.	Containment Pressure	1	C	18 months
9.	Automatic Containment Isolation Valve Position	per penetration flow path(a)	D	24 months
10.	Containment Area Radiation (High Range)	1	D	24 months
11.	Containment Hydrogen Monitors	1(c)	C	92 days
12.	Pressurizer Level	2	C	24 months
13.	SG Water Level (Narrow Range)	2 (b)	C	24 months
14.	SG Water Level (Wide Range)	2 (b)	C	24 months
15.	Steam Generator Pressure	1 per steam generator	C	24 months
16.	Condensate Storage Tank Level	1	D	24 months
17.	RWST Level, Alarm	2	C	(d)
18.	Core Exit Thermocouples Quadrant 1	2	C	24 months
19.	Core Exit Thermocouples Quadrant 2	2	C	24 months
20.	Core Exit Thermocouples Quadrant 3	2	C	24 months
21.	Core Exit Thermocouples Quadrant 4	2	C	24 months
22.	Main Steam Line Radiation	1 per steam line	D	24 months
23.	Gross Failed Fuel Detector	1	D	24 months
24.	RCS Subcooling Margin	1	C	24 months

(a) Not required for isolation valves whose associated penetration is isolated by at least one closed and deactivated automatic valve, closed manual valve, blind flange, or check valve with flow through the valve secured.

(b) Two of the four steam generators must have one OPERABLE wide range level channel and the remaining two steam generators must each have one OPERABLE level channel which may be either wide range or narrow range.

(c) Hydrogen monitor OPERABILITY requires that the associated containment fan cooler unit is OPERABLE.

(d) 18 months for RWST level alarm transmitters and 6 months for RWST alarm switches.

3.3 INSTRUMENTATION

3.3.4 Remote Shutdown

LCO 3.3.4 The Remote Shutdown Functions shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

-----------------------------------NOTES-----------------------------------

1. LCO 3.0.4 is not applicable.
2. Separate Condition entry is allowed for each Function.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required Functions inoperable.	A.1 Restore required Function to OPERABLE status.	30 days
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 4.	6 hours 12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.4.1	Perform CHANNEL CHECK for each required instrumentation channel that is normally energized.	31 days
SR 3.3.4.2	Verify each required control circuit and transfer switch is capable of performing the intended function.	24 months
SR 3.3.4.3	------------------NOTE------------------ Neutron detectors are excluded from CHANNEL CALIBRATION. --------------------------------------- Perform CHANNEL CALIBRATION for each required instrumentation channel.	24 months

3.3 INSTRUMENTATION

3.3.5 Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation

LCO 3.3.5 One channel per bus of the Undervoltage (480 V bus) Function and two channels per bus of the Degraded Voltage (480 V bus) Function shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4,
When associated DG is required to be OPERABLE by LCO 3.8.2, "AC Sources - Shutdown."

ACTIONS

------------------------------------NOTE------------------------------------
Separate Condition entry is allowed for each Function.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required channel of Undervoltage Function inoperable in one or more buses.	A.1 Restore channel to OPERABLE status.	1 hour
B. One channel of Degraded Voltage Function inoperable in one or more buses.	B.1 Place channel in trip.	1 hour

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Required Action and associated Completion Time not met. OR Two channels of Degraded Voltage Function inoperable in one or more buses.	C.1 Enter applicable Condition(s) and Required Action(s) for the associated DG made inoperable by LOP DG start instrumentation.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.5.1	Perform TADOT.	31 days
SR 3.3.5.2	Perform CHANNEL CALIBRATION with Allowable Value as follows:	
	a. Undervoltage (480 V bus) Relay Allowable Value ≥ 200 V.	24 months
	b. Degraded Voltage (480 V bus) Relay (Non-SI) Allowable Value ≥ 421 V with a time delay ≤ 45 seconds.	18 months
	c. Degraded Voltage (480 V bus) Relay (Coincident SI) Allowable Value ≥ 421 V with a time delay ≤ 10 seconds.	18 monhts

3.3 INSTRUMENTATION

3.3.6 Containment Purge System and Pressure Relief Line Isolation Instrumentation

LCO 3.3.6 The Containment Purge System and Pressure Relief Line Isolation instrumentation for each Function in Table 3.3.6-1 shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4,
During CORE ALTERATIONS,
During movement of irradiated fuel assemblies within containment.

ACTIONS

-------------------------------------NOTE-------------------------------------
Separate Condition entry is allowed for each Function.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One radiation monitoring channel inoperable.	A.1 Restore the affected channel to OPERABLE status.	7 days

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. ---------NOTE-------- Only applicable in MODE 1, 2, 3, or 4. --------------------- One or more pressure relief line isolation Functions with one or more automatic actuation trains inoperable. <u>OR</u> Two radiation monitoring channels inoperable. <u>OR</u> Required Action and associated Completion Time of Condition A not met.	B.1	Enter applicable Conditions and Required Actions of LCO 3.6.3, "Containment Isolation Valves," for containment pressure relief line isolation valves made inoperable by isolation instrumentation.	Immediately

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. ---------NOTE--------- Only applicable during CORE ALTERATIONS or movement of irradiated fuel assemblies within containment. ---------------------	C.1	Place and maintain containment purge system supply and exhaust valves in closed position.	Immediately
	<u>OR</u>		
One or more containment purge system isolation Functions with one or more automatic actuation trains inoperable. <u>OR</u> Two radiation monitoring channels inoperable. <u>OR</u> Required Action and associated Completion Time for Condition A not met.	C.2	Enter applicable Conditions and Required Actions of LCO 3.9.3, "Containment Penetrations," for containment purge system supply and exhaust isolation valves made inoperable by isolation instrumentation.	Immediately

SURVEILLANCE REQUIREMENTS

------------------------------------NOTE------------------------------------
Refer to Table 3.3.6-1 to determine which SRs apply for each Containment Purge System and Pressure Relief Line Isolation Function.

SURVEILLANCE		FREQUENCY
SR 3.3.6.1	Perform CHANNEL CHECK.	24 hours
SR 3.3.6.2	Perform ACTUATION LOGIC TEST.	31 days on a STAGGERED TEST BASIS
SR 3.3.6.3	Perform COT.	92 days
SR 3.3.6.4	------------------NOTE------------------ Verification of setpoint is not required. -- Perform TADOT.	24 months
SR 3.3.6.5	Perform CHANNEL CALIBRATION.	24 months

Table 3.3.6-1 (page 1 of 1)
Containment Purge System and Pressure Relief Line Isolation Instrumentation

	FUNCTION	REQUIRED CHANNELS	SURVEILLANCE REQUIREMENTS	TRIP SETPOINT
1.	Automatic Actuation Logic and Actuation Relays	2 trains	SR 3.3.6.2 SR 3.3.6.4	NA
2.	Gaseous Radiation Monitor (R-12)	1	SR 3.3.6.1 SR 3.3.6.3 SR 3.3.6.5	(b)
3.	Particulate Radiation Monitor (R-11)	1	SR 3.3.6.1 SR 3.3.6.3 SR 3.3.6.5	(b)
4.	ESFAS Function 1, Safety Injection, and ESFAS Function 2, Containment Spray (a)	Refer to LCO 3.3.2, ESFAS Instrumentation, Functions 1 and 2, for all initiation functions and requirements.		

(a) Only required in MODES 1, 2, 3 and 4 as specified in LCO 3.3.2.

(b) As specified in the IP3 Offsite Dose Calculation Manual.

3.3 INSTRUMENTATION

3.3.7 Control Room Ventilation System (CRVS) Actuation Instrumentation

LCO 3.3.7 The CRVS actuation instrumentation for each Function in Table 3.3.7-1 shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, 4

ACTIONS

------------------------------------NOTE------------------------------------
Separate Condition entry is allowed for each Function.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Functions with one channel or train inoperable.	A.1 Place CRVS in 10% incident mode.	7 days
B. One or more Functions with two channels or two trains inoperable.	B.1.1 Place CRVS in 10% incident mode.	72 hours
C. Required Action and associated Completion Time for Condition A or B not met.	C.1 Be in MODE 3. <u>AND</u> C.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

------------------------------------NOTE------------------------------------
Refer to Table 3.3.7-1 to determine which SRs apply for each CRVS Actuation Function.

SURVEILLANCE		FREQUENCY
SR 3.3.7.1	Perform COT.	92 days
SR 3.3.7.2	--------------------NOTE-------------------- Verification of setpoint is not required. -- Perform TADOT.	24 months

Table 3.3.7-1 (page 1 of 1)
CRVS Actuation Instrumentation

	FUNCTION	REQUIRED CHANNELS	SURVEILLANCE REQUIREMENTS	TRIP SETPOINT
1.	Manual Initiation	2	SR 3.3.7.2	NA
2.	Automatic Actuation Logic and Actuation Relays	2 trains	SR 3.3.7.1	NA
3.	Safety Injection	Refer to LCO 3.3.2, "ESFAS Instrumentation," Function 1, for all initiation functions and requirements.		

3.3 INSTRUMENTATION

3.3.8 Fuel Storage Building Emergency Ventilation System (FSBEVS) Actuation Instrumentation

LCO 3.3.8 FSBEVS actuation instrumentation shall be OPERABLE.

APPLICABILITY: During movement of irradiated fuel in the fuel storage building.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. FSBEVS actuation instrumentation inoperable.	A.1 Place FSBEVS in operation.	Immediately
	OR	
	A.2 Suspend movement of irradiated fuel in the fuel storage building.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.3.8.1	Perform CHANNEL CHECK.	24 hours
SR 3.3.8.2	Perform COT.	92 days
SR 3.3.8.3	Perform CHANNEL CALIBRATION.	24 months

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.1 RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits

LCO 3.4.1 RCS DNB parameters for pressurizer pressure, RCS average temperature, and RCS total flow rate shall be within the limits specified below:

a. Pressurizer pressure ≥ 2205 psig;

b. RCS average loop temperature ≤ 571.5°F; and

c. RCS total flow rate ≥ 375,600 gpm.

APPLICABILITY: MODE 1.

-----------------------------NOTE-----------------------------
Pressurizer pressure limit does not apply during:

a. THERMAL POWER ramp > 5% RTP per minute; or

b. THERMAL POWER step > 10% RTP.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more RCS DNB parameters not within limits.	A.1 Restore RCS DNB parameter(s) to within limit.	2 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 2.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.1.1	Verify pressurizer pressure is ≥ 2205 psig.	12 hours
SR 3.4.1.2	Verify RCS average loop temperature is ≤ 571.5°F.	12 hours
SR 3.4.1.3	Verify RCS total flow rate is ≥ 375,600 gpm.	12 hours
SR 3.4.1.4	------------------NOTE------------------ Not required to be performed until 24 hours after ≥ 90% RTP. -- Verify by precision heat balance that RCS total flow rate is ≥ 375,600 gpm.	24 months

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.2 RCS Minimum Temperature for Criticality

LCO 3.4.2 Each RCS loop average temperature (T_{avg}) shall be ≥ 540°F.

APPLICABILITY: MODE 1,
MODE 2 with k_{eff} ≥ 1.0.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. T_{avg} in one or more RCS loops not within limit.	A.1 Be in MODE 2 with k_{ef} < 1.0.	30 minutes

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.4.2.1 Verify RCS T_{avg} in each loop ≥ 540°F.	-----NOTE------ Only required if T_{avg} - T_{ref} deviation, and low T_{avg} alarm not reset and any RCS loop T_{avg} < 547°F --------------- 30 minutes thereafter

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.3 RCS Pressure and Temperature (P/T) Limits

LCO 3.4.3 RCS pressure, RCS temperature, and RCS heatup and cooldown rates shall be maintained within the limits specified in the PTLR.

APPLICABILITY: At all times.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. ---------NOTE-------- Required Action A.2 shall be completed whenever this Condition is entered. --------------------- Requirements of LCO not met in MODE 1, 2, 3, or 4.	A.1 Restore parameter(s) to within limits. <u>AND</u> A.2 Determine RCS is acceptable for continued operation.	30 minutes 72 hours
B. Required Action and associated Completion Time of Condition A not met.	B.1 Be in MODE 3. <u>AND</u> B.2 Be in MODE 5.	6 hours 36 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. ---------NOTE--------- Required Action C.2 shall be completed whenever this Condition is entered. --------------------- Requirements of LCO not met any time in other than MODE 1, 2, 3, or 4.	C.1 Initiate action to restore parameter(s) to within limits. AND C.2 Determine RCS is acceptable for continued operation.	Immediately Prior to entering MODE 4

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.3.1	------------------NOTE------------------ Only required to be performed during RCS heatup and cooldown operations and RCS inservice leak and hydrostatic testing. --	
	Verify RCS pressure, RCS temperature, and RCS heatup and cooldown rates are within the limits specified in the PTLR.	30 minutes

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.4 RCS Loops – MODES 1 and 2

LCO 3.4.4 Four RCS loops shall be OPERABLE and in operation.

APPLICABILITY: MODES 1 and 2.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Requirements of LCO not met.	A.1 Be in MODE 3.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.4.4.1 Verify each RCS loop is in operation.	12 hours

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.5 RCS Loops – MODE 3

LCO 3.4.5 Two RCS loops shall be OPERABLE, and either:

a. Two RCS loops shall be in operation when the Rod Control System is capable of rod withdrawal; or

b. One RCS loop shall be in operation when the Rod Control System is not capable of rod withdrawal.

---------------------------NOTE---------------------------

All reactor coolant pumps may not be in operation for ≤ 1 hour per 8 hour period provided:

a. No operations are permitted that would cause reduction of the RCS boron concentration; and

b. Core outlet temperature is maintained ≥ 10°F below saturation temperature.

APPLICABILITY: MODE 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required RCS loop inoperable.	A.1 Restore required RCS loop to OPERABLE status.	72 hours
B. Required Action and associated Completion Time of Condition A not met.	B.1 Be in MODE 4.	12 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One required RCS loop not in operation, and reactor trip breakers closed and Rod Control System capable of rod withdrawal.	C.1 Restore required RCS loop to operation. OR C.2 De-energize all control rod drive mechanisms (CRDMs).	1 hour 1 hour
D. Two required RCS loops inoperable. OR No RCS loop in operation.	D.1 De-energize all CRDMs. AND D.2 Suspend all operations involving a reduction of RCS boron concentration. AND D.3 Initiate action to restore one RCS loop to OPERABLE status and in operation.	Immediately Immediately Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.5.1	Verify required RCS loops are in operation.	12 hours
SR 3.4.5.2	Verify steam generator secondary side actual water level is ≥ 71% (wide range equivalent) for each required RCS loop.	12 hours
SR 3.4.5.3	Verify correct breaker alignment and indicated power are available to the required pump that is not in operation.	7 days

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.6 RCS Loops – MODE 4

LCO 3.4.6 Two loops consisting of any combination of RCS loops and residual heat removal (RHR) loops shall be OPERABLE, and one loop shall be in operation.

---------------------------- NOTES ----------------------------

1. All reactor coolant pumps (RCPs) and RHR pumps may not be in operation for ≤ 1 hour per 8 hour period provided:

   a. No operations are permitted that would cause reduction of the RCS boron concentration; and

   b. Core outlet temperature is maintained ≥ 10°F below saturation temperature.

2. No RCP shall be started with any RCS cold leg temperature less than the LTOP arming temperature unless the requirements of LCO 3.4.12, Low Temperature Overpressure Protection (LTOP), are met.

APPLICABILITY: MODE 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required RCS loop inoperable. AND Two RHR loops inoperable.	A.1 Initiate action to restore a second loop to OPERABLE status.	Immediately

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. One required RHR loop inoperable. AND Two required RCS loops inoperable.	B.1	Be in MODE 5.	24 hours
C. Required RCS or RHR loops inoperable. OR No RCS or RHR loop in operation.	C.1	Suspend all operations involving a reduction of RCS boron concentration.	Immediately
	AND		
	C.2	Initiate action to restore one loop to OPERABLE status and in operation.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.6.1	Verify one RHR or RCS loop is in operation.	12 hours
SR 3.4.6.2	Verify SG secondary side water actual level is ≥ 71% (wide range equivalent) for each required RCS loop.	12 hours
SR 3.4.6.3	Verify correct breaker alignment and indicated power are available to the required pump that is not in operation.	7 days

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.7 RCS Loops – MODE 5, Loops Filled

LCO 3.4.7 One residual heat removal (RHR) loop shall be OPERABLE and in operation, and either:

a. One additional RHR loop shall be OPERABLE; or

b. The secondary side actual water level of at least one steam generator (SG) shall be ≥ 71% (wide range equivalent).

---------------------------- NOTES ----------------------------

1. The RHR pump of the loop in operation may not be in operation for ≤ 1 hour per 8 hour period provided:

   a. No operations are permitted that would cause reduction of the RCS boron concentration; and

   b. Core outlet temperature is maintained ≥ 10°F below saturation temperature.

2. One required RHR loop may be inoperable for up to 2 hours for surveillance testing provided that the other RHR loop is OPERABLE and in operation.

3. No reactor coolant pump shall be started with the average of the RCS cold leg temperatures less than the LTOP enable temperature unless the requirements of LCO 3.4.12, Low Temperature Overpressure Protection (LTOP), are met.

4. All RHR loops may be removed from operation during planned heatup to MODE 4 when at least one RCS loop is in operation.

APPLICABILITY: MODE 5 with RCS loops filled.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One RHR loop inoperable. AND Required SGs secondary side actual water level not within the limit.	A.1	Initiate action to restore a second RHR loop to OPERABLE status.	Immediately
	OR		
	A.2	Initiate action to restore required SG secondary side water level to within the limit.	Immediately
B. Required RHR loops inoperable. OR No RHR loop in operation.	B.1	Suspend all operations involving a reduction of RCS boron concentration.	Immediately
	AND		
	B.2	Initiate action to restore one RHR loop to OPERABLE status and in operation.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.7.1	Verify one RHR loop is in operation.	12 hours
SR 3.4.7.2	Verify SG secondary side actual water level is ≥ 71% (wide range equivalent) in required SG.	12 hours
SR 3.4.7.3	Verify correct breaker alignment and indicated power are available to the required RHR pump that is not in operation.	7 days

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.8 RCS Loops – MODE 5, Loops Not Filled

LCO 3.4.8 Two residual heat removal (RHR) loops shall be OPERABLE and one RHR loop shall be in operation.

------------------------------NOTES------------------------------

1. All RHR pumps may not be in operation for ≤ 15 minutes provided:

   a. The core outlet temperature is maintained ≥ 10°F below saturation temperature.

   b. No operations are permitted that would cause a reduction of the RCS boron concentration; and

   c. No draining operations to further reduce the RCS water volume are permitted.

2. One RHR loop may be inoperable for up to 2 hours for surveillance testing provided that the other RHR loop is OPERABLE and in operation.

APPLICABILITY: MODE 5 with RCS loops not filled.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One RHR loop inoperable.	A.1	Initiate action to restore RHR loop to OPERABLE status.	Immediately

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. Required RHR loops inoperable. OR No RHR loop in operation.	B.1	Suspend all operations involving reduction in RCS boron concentration.	Immediately
	AND		
	B.2	Initiate action to restore one RHR loop to OPERABLE status and in operation.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.8.1	Verify one RHR loop is in operation.	12 hours
SR 3.4.8.2	Verify correct breaker alignment and indicated power are available to the required RHR pump that is not in operation.	7 days

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.9 Pressurizer

LCO 3.4.9 The pressurizer shall be OPERABLE with:

a. Pressurizer water level ≤ 92%; and

b. Two groups of pressurizer heaters OPERABLE with the capacity of each group ≥ 150 kW with each group powered from a different safeguards power train.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Pressurizer water level not within limit.	A.1 Be in MODE 3 with reactor trip breakers open.	6 hours
	AND	
	A.2 Be in MODE 4.	12 hours
B. One required group of pressurizer heaters inoperable.	B.1 Restore required group of pressurizer heaters to OPERABLE status.	72 hours
C. Required Action and associated Completion Time of Condition B not met.	C.1 Be in MODE 3.	6 hours
	AND	
	C.2 Be in MODE 4.	12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.9.1	Verify pressurizer water level is ≤ 92%.	12 hours
SR 3.4.9.2	Verify capacity of each required group of pressurizer heaters is ≥ 150 kW.	24 months

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.10 Pressurizer Safety Valves

LCO 3.4.10 Three pressurizer safety valves shall be OPERABLE with lift settings set ≥ 2460 psig and ≤ 2510 psig.

APPLICABILITY: MODES 1, 2, and 3,
MODE 4 with the average of the RCS cold leg temperatures greater than or equal to the LTOP arming temperature specified in LCO 3.4.12, Low Temperature Overpressure Protection (LTOP).

-----------------------------NOTE-----------------------------
The lift settings are not required to be within the LCO limits during MODES 3 and 4 for the purpose of setting the pressurizer safety valves under ambient (hot) conditions. This exception is allowed for 54 hours following entry into MODE 3 provided a preliminary cold setting was made prior to heatup.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One pressurizer safety valve inoperable.	A.1	Restore valve to OPERABLE status.	15 minutes
B. Required Action and associated Completion Time not met. OR Two or more pressurizer safety valves inoperable.	B.1 AND B.2	Be in MODE 3. Be in MODE 4 with average RCS cold leg temperature less than the LTOP arming temperature.	6 hours 12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.10.1	Verify each pressurizer safety valve is OPERABLE in accordance with the Inservice Testing Program. Following testing, lift settings shall be ≥ 2460 psig and ≤ 2510 psig.	In accordance with the Inservice Testing Program

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.11 Pressurizer Power Operated Relief Valves (PORVs)

LCO 3.4.11 Each PORV and associated block valve shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

------------------------------------NOTES------------------------------------

1. Separate Condition entry is allowed for each PORV.

2. LCO 3.0.4 is not applicable.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more PORVs inoperable and capable of being manually cycled.	A.1 Close and maintain power to associated block valve.	1 hour
B. One PORV inoperable and not capable of being manually cycled.	B.1 Close associated block valve. AND B.2 Remove power from associated block valve. AND B.3 Restore PORV to OPERABLE status.	1 hour 1 hour 7 days

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. One block valve inoperable.	C.1	Place associated PORV in manual control.	1 hour
	<u>AND</u>		
	C.2	Restore block valve to OPERABLE status.	7 days
D. Required Action and associated Completion Time of Condition A, B, or C not met.	D.1	Be in MODE 3.	6 hours
	<u>AND</u>		
	D.2	Be in MODE 4.	12 hours
E. Two PORVs inoperable and not capable of being manually cycled.	E.1	Close associated block valves.	1 hour
	<u>AND</u>		
	E.2	Remove power from associated block valves.	1 hour
	<u>AND</u>		
	E.3	Be in MODE 3.	6 hours
	<u>AND</u>		
	E.4	Be in MODE 4.	12 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
F. More than one block valve inoperable.	F.1	Place associated PORVs in manual control.	1 hour
	AND		
	F.2	Restore one block valve to OPERABLE status.	2 hours
G. Required Action and associated Completion Time of Condition F not met.	G.1	Be in MODE 3.	6 hours
	AND		
	G.2	Be in MODE 4.	12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.11.1	------------------NOTE------------------ Not required to be met with block valve closed in accordance with the Required Action of Condition B or E. -- Perform a complete cycle of each block valve.	92 days
SR 3.4.11.2	Perform a complete cycle of each PORV.	24 months

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.12 Low Temperature Overpressure Protection (LTOP)

LCO 3.4.12 LTOP shall be OPERABLE with no high head safety injection (HHSI) pumps capable of injecting into the RCS and the accumulator discharge isolation valves closed and de-energized, and either of the following:

----------------------------Note----------------------------

LCO 3.4.12.a and LCO 3.4.12.b are not Applicable when average RCS cold leg temperature is ≥ 319°F.

----

a. The Overpressure Protection System (OPS) OPERABLE with two power operated relief valves (PORVs) with lift settings within the limits specified in the PTLR;

<u>OR</u>

b. The RCS depressurized with an RCS vent of ≥ 2.00 square inches.

----------------------------NOTES----------------------------

1. Accumulator isolation is only required when accumulator pressure is greater than or equal to the maximum RCS pressure for the existing RCS cold leg temperature allowed by the P/T limit curves provided in the PTLR.
2. One HHSI pump may be made capable of injecting into the RCS as needed to support emergency boration or to respond to a loss of RHR cooling.
3. One HHSI pump may be made capable of injecting into the RCS for pump testing for a period not to exceed 8 hours.

APPLICABILITY: Whenever the RHR System is not isolated from the RCS,
MODE 4 when average RCS cold leg temperature is < 319°F,
MODE 5,
MODE 6 when the reactor vessel head is on.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or more HHSI pump(s) capable of injecting into the RCS .	A.1	Initiate action to verify no HHSI pumps are capable of injecting into the RCS.	Immediately
	<u>OR</u>		
	A.2.1	Verify RCS is vented with opening ≥ 2.00 square inches.	Immediately
	<u>AND</u>		
	A.2.2	Verify pressurizer level is ≤ 0%.	Immediately <u>AND</u> Once per 12 hours
	<u>AND</u>		
	A.2.3	Verify no more than two HHSI pumps are capable of injecting into the RCS.	Immediately <u>AND</u> Once per 12 hours
	<u>OR</u>		
	A.3.1	Verify RCS is vented with opening greater than or equal to one pressurizer code safety valve flange.	Immediately
	<u>AND</u>		
	A.3.2	Verify no more than two HHSI pumps are capable of injecting into the RCS	Immediately <u>AND</u> Once per 12 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. An accumulator discharge isolation valve not closed and de-energized when the accumulator pressure is greater than or equal to the maximum RCS pressure for existing cold leg temperature allowed in the PTLR.	B.1	Close and de-energize isolation valve for affected accumulator.	1 hour
C. Required Action and associated Completion Time of Condition B not met.	C.1.1	Increase average RCS cold leg temperature to $\geq$ 319°F.	12 hours
	<u>AND</u>		
	C.1.2	Isolate the RHR System from the RCS.	12 hours
	<u>OR</u>		
	C.2	Depressurize affected accumulator to less than the maximum RCS pressure for existing cold leg temperature allowed in the PTLR.	12 hours
D. One required PORV inoperable.	D.1	Restore required PORV to OPERABLE status.	7 days

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. Two required PORVs inoperable. <u>OR</u> Required Action and associated Completion Time of Condition C or D not met.	E.1 Depressurize RCS and establish RCS vent of ≥ 2.00 square inches.	8 hours
	<u>OR</u>	
	E.2 Increase RCS cold leg temperature to ≥ 319°F.	8 hours
	<u>OR</u>	
	E.3 Verify pressurizer level, RCS pressure, and RCS injection capability are within limits specified in PTLR for OPS not OPERABLE.	8 hours <u>AND</u> Once per 12 hours thereafter
F. LTOP inoperable for any reason other than Condition A, B, C, D, or E.	F.1 Depressurize RCS and establish RCS vent of ≥ 2.00 square inches.	8 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.4.12.1 Verify no HHSI pumps are capable of injecting into the RCS.	12 hours

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.4.12.2	Verify each accumulator discharge isolation valve is closed and de-energized; OR Verify each accumulator pressure is less than the maximum RCS pressure for the existing RCS cold leg temperature allowed by the P/T limit curves provided in the PTLR.	12 hours 12 hours
SR 3.4.12.3	------------------NOTE------------------ Only required to be met when complying with LCO 3.4.12.b. -- Verify RCS vent ≥ 2.00 square inches established.	12 hours for unlocked open vent valve(s) AND 31 days for locked open vent valve(s)
SR 3.4.12.4	----------------NOTE------------------ Only required to be met when complying with LCO 3.4.12.a. -- Perform CHANNEL CHECK of Overpressure Protection (OPS) instrument channels.	24 hours

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.4.12.5	Verify PORV block valve is open for each required PORV.	72 hours
SR 3.4.12.6	-------------------NOTE--------------------- Not required to be met until 12 hours after decreasing RCS average cold leg temperature to < 319°F. --	
	Perform a COT on each required PORV, excluding actuation.	24 months
SR 3.4.12.7	Perform CHANNEL CALIBRATION for each required OPS channel as follows:	
	a. OPS actuation channels; and	18 months
	b. RCS pressure and temperature instruments.	24 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.4.12.8	-----------------------------NOTES----------------------------- 1. Not required to be met when average RCS cold leg temperature is ≥ 319°F. 2. Not required to be met if SR 3.4.12.9 is met. -- Verify each of the following conditions are satisfied prior to starting any RCP: a. Secondary side water temperature of the hottest steam generator (SG) is less than or equal to the coldest RCS cold leg temperature; and b. RCS makeup is less than or equal to RCS losses; and c. Steam generator pressure is not decreasing; and d.1 Overpressure Protection System (OPS) is OPERABLE; OR d.2.1 RCS pressure less than nominal OPS setpoint specified in the PTLR; and d.2.2 Pressurizer level, RCS pressure, and RCS injection capability are within limits specified in PTLR for OPS not OPERABLE.	 Within 15 minutes prior to starting any RCP

(continued)

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.4.12.9	-------------------NOTES-------------------- 1. Not required to be met when average RCS cold leg temperature is ≥ 319°F. 2. Not required to be met if SR 3.4.12.8 is met. --	
	Verify each of the following conditions are satisfied prior to starting any RCP: a. Secondary side water temperature of the hottest steam generator is ≤ 64°F above the coldest RCS cold leg temperature; and b. RCS makeup is less than or equal to RCS losses; and c. Overpressure Protection System (OPS) is OPERABLE; and d. Pressurizer level is ≤ 73%; and e. Coldest RCS cold leg temperature is within limits specified in PTLR for RCP start with OPS OPERABLE and SG temperature greater than RCS cold leg temperature	Within 15 minutes prior to starting any RCP

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.13 RCS Operational LEAKAGE

LCO 3.4.13 RCS operational LEAKAGE shall be limited to:

a. No pressure boundary LEAKAGE;

b. 1 gpm unidentified LEAKAGE;

c. 10 gpm identified LEAKAGE;

d. 1 gpm total primary to secondary LEAKAGE through all steam generators (SGs); and

e. 432 gallons per day primary to secondary LEAKAGE through any one SG.

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

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. RCS LEAKAGE not within limits for reasons other than pressure boundary LEAKAGE.	A.1 Reduce LEAKAGE to within limits.	4 hours
B. Required Action and associated Completion Time of Condition A not met. OR Pressure boundary LEAKAGE exists.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.13.1	------------------NOTE------------------ Not required to be performed in MODE 3 or 4 until 12 hours of steady state operation. -- Verify RCS Operational leakage is within limits by performance of RCS water inventory balance.	-----NOTE------ Only required to be performed during steady state operation -------------- 72 hours
SR 3.4.13.2	Verify steam generator tube integrity is in accordance with the Steam Generator Tube Surveillance Program.	In accordance with the Steam Generator Tube Surveillance Program

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.14 RCS Pressure Isolation Valve (PIV) Leakage

LCO 3.4.14 Leakage from each RCS PIV shall be within limit.

APPLICABILITY: MODES 1, 2, and 3,
MODE 4, except leakage limits for valves in the residual heat removal (RHR) flow path when in, or during the transition to or from, the RHR mode of operation.

ACTIONS

------------------------------------ NOTES ------------------------------------

1. Separate Condition entry is allowed for each flow path.
2. Enter applicable Conditions and Required Actions for systems made inoperable by an inoperable PIV.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more flow paths with leakage from one or more RCS PIVs not within limit.	-------------NOTE------------- Each valve used to satisfy Required Action A.1 and Required Action A.2 must have been verified to meet SR 3.4.14.1 and be in the reactor coolant pressure boundary or the high pressure portion of the system. -----------------------------	
	A.1 Isolate the high pressure portion of the affected system from the low pressure portion by use of one closed manual, deactivated automatic, or check valve.	4 hours
	<u>AND</u>	
		(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.2.1 Isolate the high pressure portion of the affected system from the low pressure portion by use of a second closed manual, deactivated automatic, or check valve. OR A.2.2 Restore RCS PIV to within limits.	72 hours 72 hours
B. Required Action and associated Completion Time for Condition A not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 36 hours
C. RHR System autoclosure interlock function inoperable.	------------NOTE------------ RHR system flowpath may be unisolated under administrative controls if needed to meet requirements for an operating RCS loop. --------------------------- C.1 Isolate the affected penetration by use of one closed manual or deactivated automatic valve.	 4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.14.1	-------------------NOTES------------------- 1. Not required to be performed in MODES 3 and 4. 2. Not required to be performed on the RCS PIVs located in the RHR flow path when in the shutdown cooling mode of operation. 3. RCS PIVs actuated during the performance of this Surveillance are not required to be tested more than once if a repetitive testing loop cannot be avoided. -- Verify leakage from each RCS PIV is equivalent to ≤ 0.5 gpm per nominal inch of valve size up to a maximum of 5 gpm at an RCS pressure ≥ 2215 psig and ≤ 2255 psig.	24 months AND Prior to entering MODE 2 whenever the unit has been in MODE 5 for 7 days or more, if leakage testing has not been performed in the previous 12 months AND Within 24 hours following valve actuation due to automatic or manual action or flow through the valve

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.4.14.2	Verify RHR System autoclosure interlock prevents the valves from being opened with a simulated or actual RCS pressure signal ≥ 450 psig.	24 months
SR 3.4.14.3	Verify RHR System autoclosure interlock causes the valves to close automatically with a simulated or actual RCS pressure signal ≥ 550 psig.	24 months

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.15 RCS Leakage Detection Instrumentation

LCO 3.4.15 The following RCS leakage detection instrumentation shall be OPERABLE:

a. One containment sump discharge flow monitor;

b. One containment atmosphere radioactivity monitor (gaseous or particulate); and

c. One containment fan cooler unit condensate measuring system.

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

ACTIONS

-------------------------------------NOTE-------------------------------------
LCO 3.0.4 is not applicable.

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. Required containment sump flow monitor inoperable.	A.1	Perform SR 3.4.13.1.	Once per 24 hours
	AND		
	A.2	Restore required containment sump monitor to OPERABLE status.	30 days

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Required containment atmosphere radioactivity monitor inoperable.	B.1.1 Analyze grab samples of the containment atmosphere.	Once per 24 hours
	<u>OR</u>	
	B.1.2 Perform SR 3.4.13.1.	Once per 24 hours
	<u>AND</u>	
	B.2.1 Restore required containment atmosphere radioactivity monitor to OPERABLE status.	30 days
	<u>OR</u>	
	B.2.2 Verify containment fan cooler unit condensate measuring system is OPERABLE.	30 days
C. Required containment fan cooler unit condensate measuring system inoperable.	C.1 Perform SR 3.4.15.1.	Once per 8 hours
	<u>OR</u>	
	C.2 Perform SR 3.4.13.1.	Once per 24 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Required containment atmosphere radioactivity monitor inoperable. <u>AND</u> Required containment fan cooler unit condensate measuring system inoperable.	D.1 Restore required containment atmosphere radioactivity monitor to OPERABLE status. <u>OR</u> D.2 Restore required containment fan cooler unit condensate measuring system to OPERABLE status.	30 days 30 days
E. Required Action and associated Completion Time not met.	E.1 Be in MODE 3. <u>AND</u> E.2 Be in MODE 5.	6 hours 36 hours
F. All required monitors inoperable.	F.1 Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.15.1	Perform CHANNEL CHECK of the required containment atmosphere radioactivity monitor.	12 hours
SR 3.4.15.2	Perform COT of the required containment atmosphere radioactivity monitor.	92 days
SR 3.4.15.3	Perform CHANNEL CALIBRATION of the required containment sump flow monitor.	24 months
SR 3.4.15.4	Perform CHANNEL CALIBRATION of the required containment atmosphere radioactivity monitor.	24 months
SR 3.4.15.5	Perform CHANNEL CALIBRATION of the required containment fan cooler unit condensate measuring system.	24 months

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.16 RCS Specific Activity

LCO 3.4.16 The specific activity of the reactor coolant shall be within limits.

APPLICABILITY: MODES 1 and 2,
MODE 3 with RCS loop average temperature (T_{avg}) ≥ 500°F.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. DOSE EQUIVALENT I-131 > 1.0 μCi/gm.	------------- NOTE ------------- LCO 3.0.4 is not applicable. -----------------------------	
	A.1 Verify DOSE EQUIVALENT I-131 within the acceptable region of Figure 3.4.16-1.	Once per 4 hours
	<u>AND</u>	
	A.2 Restore DOSE EQUIVALENT I-131 to within limit.	48 hours
B. Gross specific activity of the reactor coolant not within limit of SR 3.4.16.1.	B.1 Be in MODE 3 with T_{avg} < 500°F.	6 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. Required Action and associated Completion Time of Condition A not met. OR DOSE EQUIVALENT I-131 in the unacceptable region of Figure 3.4.16-1.	C.1	Be in MODE 3 with T_{avg} < 500°F.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.16.1	Verify reactor coolant gross specific activity ≤ 100/Ē μCi/gm.	7 days
SR 3.4.16.2	------------------NOTE------------------ Only required to be performed in MODE 1. -- Verify reactor coolant DOSE EQUIVALENT I-131 specific activity ≤ 1.0 μCi/gm.	14 days AND Between 2 and 6 hours after a THERMAL POWER change of ≥ 15% RTP within a 1 hour period
SR 3.4.16.3	------------------NOTE------------------ Not required to be performed until 31 days after a minimum of 2 effective full power days and 20 days of MODE 1 operation have elapsed since the reactor was last subcritical for ≥ 48 hours. -- Determine Ē from a sample taken in MODE 1 after a minimum of 2 effective full power days and 20 days of MODE 1 operation have elapsed since the reactor was last subcritical for ≥ 48 hours.	184 days

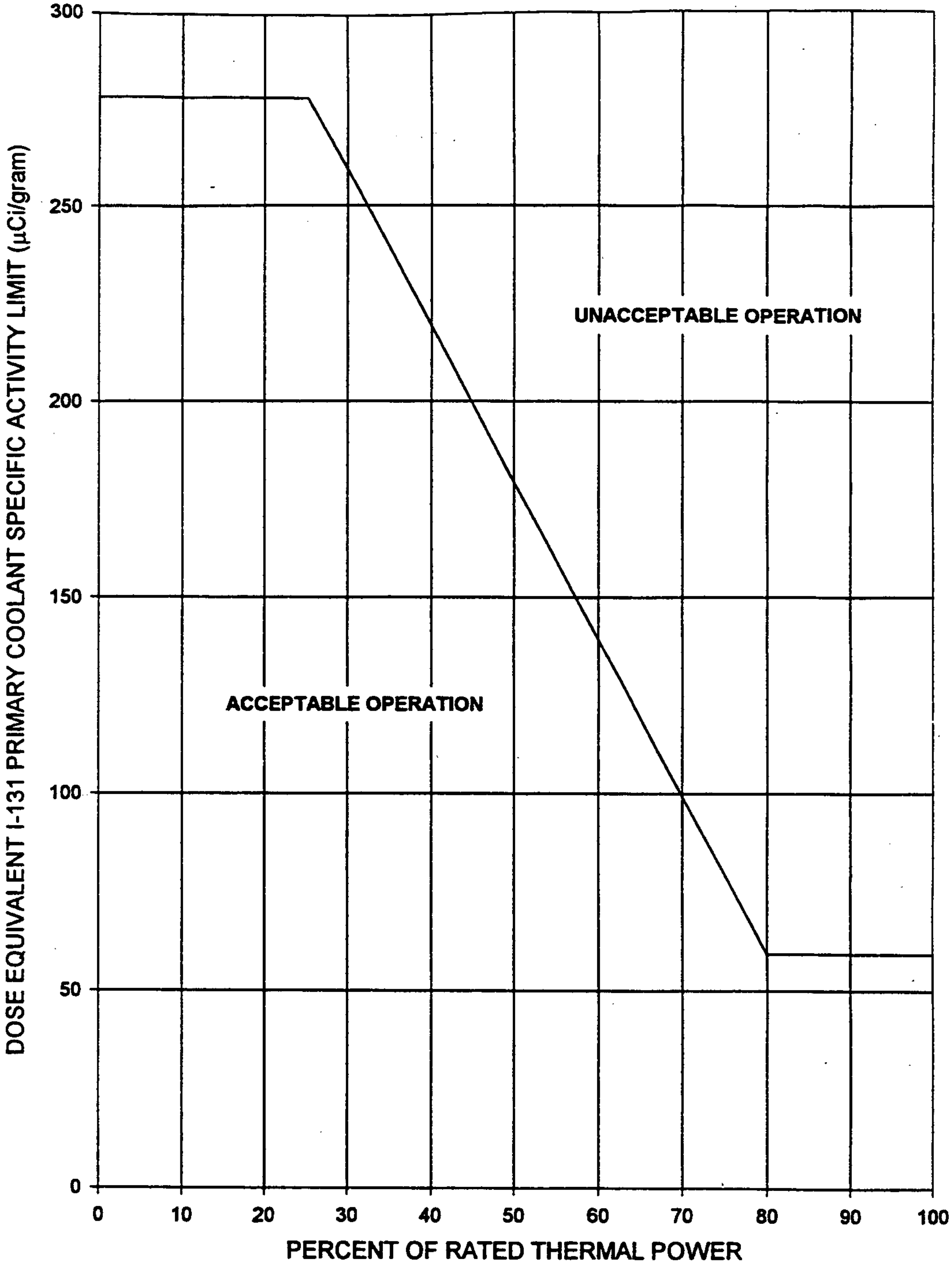

Figure 3.4.16-1 (page 1 of 1)
Reactor Coolant DOSE EQUIVALENT I-31 Specific Activity
Limit Versus Percent of RATED THERMAL POWER
(Primary Coolant Specific Activity is greater than
1.0 µCi/gram DOSE EQUIVALENT I-131)

3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

3.5.1 Accumulators

LCO 3.5.1 Four ECCS accumulators shall be OPERABLE.

APPLICABILITY: MODES 1 and 2,
MODE 3 with reactor coolant system pressure > 1000 psig.

-----------------------NOTES-----------------------

1. In MODE 3, all accumulator discharge isolation valves may be closed and energized for up to 8 hours during the performance of reactor coolant system hydrostatic testing.

2. In MODE 3, one accumulator discharge isolation valve may be closed and energized for up to 8 hours for accumulator check valve leakage testing.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One accumulator inoperable due to boron concentration not within limits of SR 3.5.1.4.	A.1 Restore boron concentration to within limits of SR 3.5.1.4.	72 hours
B. One accumulator inoperable for reasons other than Condition A.	B.1 Restore accumulator to OPERABLE status.	1 hour

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Required Action and associated Completion Time of Condition A or B not met.	C.1 Be in MODE 3. <u>AND</u> C.2 Reduce reactor coolant system pressure to ≤ 1000 psig.	6 hours 12 hours
D. Two or more accumulators inoperable.	D.1 Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.1.1	Verify each accumulator discharge isolation valve is fully open.	12 hours
SR 3.5.1.2	Verify borated water volume in each accumulator is ≥ 775 cubic feet and ≤ 815 cubic feet.	12 hours
SR 3.5.1.3	Verify nitrogen cover pressure in each accumulator is ≥ 600 psig and ≤ 700 psig.	12 hours

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.5.1.4	Verify boron concentration in each accumulator is ≥ 2000 ppm and ≤ 2600 ppm.	31 days AND -----NOTE------ Only required to be performed for affected accumulators --------------- Once within 6 hours after each solution volume increase of ≥ 3 cubic feet, 10 % of indicated level, that is not the result of addition from the refueling water storage tank
SR 3.5.1.5	Verify power is removed from each accumulator isolation valve operator when reactor coolant system pressure is ≥ 2000 psig.	31 days

3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

3.5.2 ECCS – Operating

LCO 3.5.2 Three ECCS trains shall be OPERABLE.

--------------------------NOTES--------------------------

1. In MODE 3, both HHSI flow paths may be isolated by closing the isolation valves for up to 2 hours to perform pressure isolation valve testing per SR 3.4.14.1.

2. Operation in MODE 3 with HHSI pumps made incapable of injecting pursuant to LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP)," is allowed for up to 4 hours or until the temperature of all RCS cold legs exceeds 375°F, whichever comes first.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more trains inoperable. AND At least 100% of the ECCS flow equivalent to OPERABLE ECCS trains available.	A.1 Restore train(s) to OPERABLE status.	72 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	6 hours
	AND	
	B.2 Be in MODE 4.	12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.2.1	Verify the following valves are in the listed position with power to the valve operator removed. Number / Position / Function SI-856B Closed HHSI Loop 33 Hot Leg Injection Stop Valve SI-856G Closed HHSI Loop 31 Hot Leg Injection Stop Valve SI-1810 Open RWST outlet isolation AC-744 Open Common discharge isolation for RHR pumps SI-882 Open Common RWST suction isolation for RHR pumps SI-842 Open HHSI pump minimum flow line isolation SI-843 Open HHSI pump minimum flow line isolation SI-883 Closed RHR pump return to RWST isolation AC-1870 Open RHR pump minimum flow line isolation AC-743 Open RHR pump minimum flow line isolation	12 hours

Number	Position	Function
SI-856B	Closed	HHSI Loop 33 Hot Leg Injection Stop Valve
SI-856G	Closed	HHSI Loop 31 Hot Leg Injection Stop Valve
SI-1810	Open	RWST outlet isolation
AC-744	Open	Common discharge isolation for RHR pumps
SI-882	Open	Common RWST suction isolation for RHR pumps
SI-842	Open	HHSI pump minimum flow line isolation
SI-843	Open	HHSI pump minimum flow line isolation
SI-883	Closed	RHR pump return to RWST isolation
AC-1870	Open	RHR pump minimum flow line isolation
AC-743	Open	RHR pump minimum flow line isolation

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.5.2.2	Verify that each ECCS manual, power operated, and automatic valve in the flow path, that is not locked, sealed, or otherwise secured in position, is in the correct position.	31 days
SR 3.5.2.3	Verify each ECCS pump's developed head at the test flow point is greater than or equal to the required developed head.	In accordance with the Inservice Testing Program
SR 3.5.2.4	Verify each ECCS automatic valve in the flow path that is not locked, sealed, or otherwise secured in position, actuates to the correct position on an actual or simulated actuation signal.	24 months
SR 3.5.2.5	Verify each ECCS pump starts automatically on an actual or simulated actuation signal.	24 months
SR 3.5.2.6	Verify, for each ECCS throttle valve listed below, each position stop is in the correct position. <u>Valve Numbers</u> SI-856A SI-856F SI-856C SI-856H SI-856D SI-856J SI-856E SI-856K	24 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.5.2.7	Verify, by visual inspection, each ECCS train containment sump suction inlet and recirculation sump suction inlet is not restricted by debris and the suction inlet screens show no evidence of structural distress or abnormal corrosion.	24 months

3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

3.5.3 ECCS – Shutdown

LCO 3.5.3 One ECCS residual heat removal (RHR) subsystem and one ECCS recirculation subsystem shall be OPERABLE.

--------------------------- NOTE ---------------------------
An RHR train may be considered OPERABLE during alignment and operation for decay heat removal, if capable of being manually realigned to the ECCS mode of operation.

APPLICABILITY: MODE 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Required ECCS residual heat removal (RHR) subsystem inoperable.	A.1 Initiate action to restore required ECCS RHR subsystem to OPERABLE status.	Immediately
B. Required ECCS Recirculation subsystem inoperable.	B.1 Restore required ECCS recirculation subsystem to OPERABLE status.	1 hour
C. Required Action and associated Completion Time of Condition B not met.	C.1 Be in MODE 5.	24 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.3.1	The following SRs are applicable for all equipment required to be OPERABLE: SR 3.5.2.3 SR 3.5.2.7	In accordance with applicable SRs

3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

3.5.4 Refueling Water Storage Tank (RWST)

LCO 3.5.4 The RWST shall be OPERABLE.

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

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. RWST boron concentration not within limits of SR 3.5.4.3. OR RWST borated water temperature not within limits of SR 3.5.4.1.	A.1 Restore RWST to OPERABLE status.	8 hours
B. RWST inoperable for reasons other than Condition A.	B.1 Restore RWST to OPERABLE status.	1 hour
C. Required Action and associated Completion Time not met.	C.1 Be in MODE 3. AND C.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.4.1	-----------------NOTE------------------ Only required to be performed when ambient air temperature remains < 40°F or > 100°F for 24 hours. --------------------------------------- Verify RWST borated water temperature is ≥ 40°F and ≤ 110°F.	24 hours
SR 3.5.4.2	Verify RWST borated water level is ≥ 35.4 feet.	7 days
SR 3.5.4.3	Verify RWST boron concentration is ≥ 2400 ppm and ≤ 2600 ppm.	31 days

3.6 CONTAINMENT SYSTEMS

3.6.1 Containment

LCO 3.6.1 Containment shall be OPERABLE.

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

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. Containment inoperable.	A.1	Restore containment to OPERABLE status.	1 hour
B. Required Action and associated Completion Time not met.	B.1	Be in MODE 3.	6 hours
	<u>AND</u>		
	B.2	Be in MODE 5.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.1.1	Perform required visual examinations and leakage rate testing except for containment air lock testing, in accordance with the Containment Leakage Rate Testing Program.	-----NOTE------ SR 3.0.2 is not applicable --------------- In accordance with the Containment Leakage Rate Testing Program

3.6 CONTAINMENT SYSTEMS

3.6.2 Containment Air Locks

LCO 3.6.2 Two containment air locks shall be OPERABLE.

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

ACTIONS

-------------------------------------NOTES-------------------------------------

1. Entry and exit is permissible to perform repairs on the affected air lock components.

2. Separate Condition entry is allowed for each air lock.

3. Enter applicable Conditions and Required Actions of LCO 3.6.1, "Containment," when air lock leakage results in exceeding the overall containment leakage rate.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more containment air locks with one containment air lock door inoperable.	------------NOTES------------ 1. Required Actions A.1, A.2, and A.3 are not applicable if both doors in the same air lock are inoperable and Condition C is entered. 2. Entry and exit is permissible for 7 days under administrative controls if both air locks are inoperable. -----------------------------	
		(continued)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. (continued)	A.1	Verify the OPERABLE door is closed in the affected air lock.	1 hour
	AND		
	A.2	Lock the OPERABLE door closed in the affected air lock.	24 hours
	AND		
	A.3	--------NOTE----------- Air lock doors in high radiation areas may be verified locked closed by administrative means. ----------------------	
		Verify the OPERABLE door is locked closed in the affected air lock.	Once per 31 days

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One or more containment air locks with containment air lock interlock mechanism inoperable.	-------------NOTES------------- 1. Required Actions B.1, B.2, and B.3 are not applicable if both doors in the same air lock are inoperable and Condition C is entered. 2. Entry and exit of containment is permissible under the control of a dedicated individual. ------------------------------	
	B.1 Verify an OPERABLE door is closed in the affected air lock.	1 hour
	<u>AND</u>	
	B.2 Lock an OPERABLE door closed in the affected air lock.	24 hours
	<u>AND</u>	
	B.3 ---------NOTE--------- Air lock doors in high radiation areas may be verified locked closed by administrative means. --------------------- Verify an OPERABLE door is locked closed in the affected air lock.	Once per 31 days

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. One or more containment air locks inoperable for reasons other than Condition A or B.	C.1	Initiate action to evaluate overall containment leakage rate per LCO 3.6.1.	Immediately
	<u>AND</u>		
	C.2	Verify a door is closed in the affected air lock.	1 hour
	<u>AND</u>		
	C.3	Restore air lock to OPERABLE status.	24 hours
D. Required Action and associated Completion Time not met.	D.1	Be in MODE 3.	6 hours
	<u>AND</u>		
	D.2	Be in MODE 5.	36 hours

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.6.2.1	-------------------NOTES------------------- 1. An inoperable air lock door does not invalidate the previous successful performance of the overall air lock leakage test. 2. Results shall be evaluated against acceptance criteria applicable to SR 3.6.1.1, the integrated leak rate test. --- Perform required air lock leakage rate testing in accordance with the Containment Leakage Rate Testing Program.	In accordance with the Containment Leakage Rate Testing Program
SR 3.6.2.2	Verify only one door in the air lock can be opened at a time.	24 months

3.6 CONTAINMENT SYSTEMS

3.6.3 Containment Isolation Valves

LCO 3.6.3 Each containment isolation valve shall be OPERABLE.

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

ACTIONS

------------------------------------NOTES------------------------------------

1. Penetration flow path(s) except for 36 inch purge valve flow paths may be unisolated intermittently under administrative controls.

2. Separate Condition entry is allowed for each penetration flow path.

3. Enter applicable Conditions and Required Actions for systems made inoperable by containment isolation valves.

4. Enter applicable Conditions and Required Actions of LCO 3.6.1, "Containment," when isolation valve leakage results in exceeding the overall containment leakage rate acceptance criteria.

5. Enter applicable Conditions and Required Actions of LCO 3.6.9, "Isolation Valve Seal Water (IVSW) System," when required IVSW supply to a penetration flowpath is inoperable.

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. ---------NOTE-------- Only applicable to penetration flow paths with two or more containment isolation valves. -------------------- One or more penetration flow paths with one containment isolation valve inoperable.	A.1	Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, blind flange, or check valve with flow through the valve secured.	4 hours
	<u>AND</u>		
	A.2	--------NOTE-------- Isolation devices in high radiation areas may be verified by use of administrative means. -------------------- Verify the affected penetration flow path is isolated.	Once per 31 days for isolation devices outside containment <u>AND</u> Prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days for isolation devices inside containment

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. ---------NOTE--------- Only applicable to penetration flow paths with two or more containment isolation valves. --------------------- One or more penetration flow paths with two containment isolation valves inoperable.	B.1	Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, or blind flange.	1 hour
C. ---------NOTE--------- Only applicable to penetration flow paths with only one containment isolation valve and a closed system. --------------------- One or more penetration flow paths with one containment isolation valve inoperable.	C.1	Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, or blind flange.	72 hours
	<u>AND</u>		
	C.2	--------NOTE--------- Isolation devices in high radiation areas may be verified by use of administrative means. -------------------- Verify the affected penetration flow path is isolated.	Once per 31 days

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
D. Required Action and associated Completion Time not met.	D.1	Be in MODE 3.	6 hours
	AND		
	D.2	Be in MODE 5.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.3.1	Verify each 36 inch purge supply and exhaust isolation valve is sealed closed.	31 days
SR 3.6.3.2	Verify each 10 inch pressure relief isolation valve is closed, except when these valves are open for pressure control, ALARA or air quality considerations for personnel entry, or for Surveillances that require the valves to be open.	31 days

(continued)

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.6.3.3	-------------------NOTE------------------- Valves and blind flanges in high radiation areas may be verified by use of administrative controls. -- Verify each containment isolation manual valve and blind flange that is located outside containment and not locked, sealed, or otherwise secured and required to be closed during accident conditions is closed, except for containment isolation valves that are open under administrative controls.	31 days
SR 3.6.3.4	-------------------NOTE------------------- Valves and blind flanges in high radiation areas may be verified by use of administrative means. -- Verify each containment isolation manual valve and blind flange that is located inside containment and not locked, sealed or otherwise secured and required to be closed during accident conditions is closed, except for containment isolation valves that are open under administrative controls.	Prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.6.3.5	Verify the isolation time of each power operated and each automatic power operated containment isolation valve is within limits.	In accordance with the Inservice Testing Program
SR 3.6.3.6	Verify each automatic containment isolation valve that is not locked, sealed or otherwise secured in position, actuates to the isolation position on an actual or simulated actuation signal.	24 months
SR 3.6.3.7	Verify each 10 inch containment pressure relief line isolation valve is blocked to restrict valve opening to $\leq$ 60 degrees.	24 months
SR 3.6.3.8	Verify the combined leakage rate for all containment bypass leakage paths in accordance with the Containment Leakage Rate Testing Program.	In accordance with the Containment Leakage Rate Testing Program

3.6 CONTAINMENT SYSTEMS

3.6.4 Containment Pressure

LCO 3.6.4 Containment pressure shall be ≥ -2.0 psig and ≤ +2.5 psig.

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

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Containment pressure not within limits.	A.1 Restore containment pressure to within limits.	1 hour
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	6 hours
	<u>AND</u>	
	B.2 Be in MODE 5.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.6.4.1 Verify containment pressure is within limits.	12 hours

3.6 CONTAINMENT SYSTEMS

3.6.5 Containment Air Temperature

LCO 3.6.5 Containment average air temperature shall be ≤ 130°F.

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

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Containment average air temperature not within limit.	A.1 Restore containment average air temperature to within limit.	8 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.6.5.1 Verify containment average air temperature is within limit.	24 hours

3.6 CONTAINMENT SYSTEMS

3.6.6 Containment Spray System and Containment Fan Cooler System

LCO 3.6.6 Two Containment Spray trains and three Containment Fan Cooler trains shall be OPERABLE.

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

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One containment spray train inoperable.	A.1 Restore containment spray train to OPERABLE status.	72 hours <u>AND</u> 10 days from discovery of failure to meet the LCO
B. Required Action and associated Completion Time of Condition A not met.	B.1 Be in MODE 3. <u>AND</u> B.2 Be in MODE 5.	6 hours 84 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One containment fan cooler train inoperable.	C.1 Restore containment fan cooler train to OPERABLE status.	7 days <u>AND</u> 10 days from discovery of failure to meet the LCO
D. Two containment fan cooler trains inoperable.	D.1 Restore one containment fan cooler train to OPERABLE status.	72 hours
E. Required Action and associated Completion Time of Condition C or D not met.	E.1 Be in MODE 3. <u>AND</u> E.2 Be in MODE 5.	6 hours 84 hours
F. Two containment spray trains inoperable. <u>OR</u> Any combination of three or more trains inoperable.	F.1 Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.6.1	Verify each containment spray manual, power operated, and automatic valve in the flow path that is not locked, sealed, or otherwise secured in position is in the correct position.	31 days
SR 3.6.6.2	Operate each containment fan cooler unit fan for ≥ 15 minutes.	92 days
SR 3.6.6.3	Verify each containment fan cooler unit cooling water flow rate is ≥ 1400 gpm.	92 days
SR 3.6.6.4	Verify each containment spray pump's developed head at the flow test point is greater than or equal to the required developed head.	In accordance with the Inservice Testing Program
SR 3.6.6.5	Verify each automatic containment spray valve in the flow path that is not locked, sealed, or otherwise secured in position, actuates to the correct position on an actual or simulated actuation signal.	24 months
SR 3.6.6.6	Verify each containment spray pump starts automatically on an actual or simulated actuation signal.	24 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.6.6.7	Verify each containment fan cooler unit starts and dampers re-position to the emergency mode automatically on an actual or simulated actuation signal.	24 months
SR 3.6.6.8	Perform required containment fan cooler system filter testing in accordance with the Ventilation Filter Testing Program (VFTP).	In accordance with the VFTP
SR 3.6.6.9	Verify each spray nozzle is unobstructed.	10 years

3.6 CONTAINMENT SYSTEMS

3.6.7 Spray Additive System

LCO 3.6.7 The Spray Additive System shall be OPERABLE.

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

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Spray Additive System inoperable.	A.1 Restore Spray Additive System to OPERABLE status.	72 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	6 hours
	<u>AND</u>	
	B.2 Be in MODE 5.	84 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.7.1	Verify each spray additive manual, power operated, and automatic valve in the flow path that is not locked, sealed, or otherwise secured in position is in the correct position.	31 days

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.6.7.2	Verify spray additive tank solution volume is ≥ 4000 gal.	184 days
SR 3.6.7.3	Verify spray additive tank NaOH solution concentration is ≥ 35% and ≤ 38% by weight.	184 days
SR 3.6.7.4	Verify each spray additive automatic valve in the flow path that is not locked, sealed, or otherwise secured in position, actuates to the correct position on an actual or simulated actuation signal.	24 months
SR 3.6.7.5	Verify spray additive system flow from each flow path.	5 years

3.6 CONTAINMENT SYSTEMS

3.6.8 Hydrogen Recombiners

LCO 3.6.8 Two hydrogen recombiners shall be OPERABLE.

APPLICABILITY: MODES 1 and 2.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One hydrogen recombiner inoperable.	A.1 ---------NOTE--------- LCO 3.0.4 is not applicable. --------------------- Restore hydrogen recombiner to OPERABLE status.	30 days
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.8.1	Perform a system functional test for each hydrogen recombiner.	6 months
SR 3.6.8.2	Visually examine each hydrogen recombiner enclosure and verify there is no evidence of abnormal conditions.	24 months
SR 3.6.8.3	Perform a resistance to ground test for each heater phase.	24 months

3.6 CONTAINMENT SYSTEMS

3.6.9 Isolation Valve Seal Water (IVSW) System

LCO 3.6.9 The IVSW System shall be OPERABLE.

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

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One IVSW system header inoperable. OR One IVSW automatic actuation valve inoperable.	A.1 Restore IVSW system to OPERABLE status.	7 days
B. IVSW system inoperable for reasons other than Condition A.	B.1 Restore IVSW System to OPERABLE Status.	24 hours
C. Required Action and associated Completion Time not met.	C.1 Be in MODE 3. AND C.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.9.1	Verify IVSW tank pressure is ≥ 47 psig.	24 hours
SR 3.6.9.2	Verify IVSW nitrogen supply bank includes a minimum of 3 cylinders and that each cylinder has a pressure ≥ 150 psig.	24 hours
SR 3.6.9.3	Verify the IVSW tank water volume is ≥ 144 gallons.	24 hours
SR 3.6.9.4	Verify the opening time of each air operated header injection valve is within limits.	In accordance with the Inservice Testing Program
SR 3.6.9.5	Verify each automatic valve in the IVSW System actuates to the correct position on an actual or simulated actuation signal.	24 months
SR 3.6.9.6	Verify the leakage rate of water from the Isolation Valve Seal Water System in accordance with the Containment Leakage Rate Testing Program.	In accordance with the Containment Leakage Rate Testing Program.

3.7 PLANT SYSTEMS

3.7.1 Main Steam Safety Valves (MSSVs)

LCO 3.7.1 The MSSVs shall be OPERABLE as specified in Table 3.7.1-1 and Table 3.7.1-2.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

------------------------------------NOTE------------------------------------
Separate Condition entry is allowed for each MSSV.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required MSSVs inoperable.	A.1 Reduce neutron flux trip setpoint to less than or equal to the applicable % RTP listed in Table 3.7.1-1.	4 hours
B. Required Action and associated Completion Time not met. <u>OR</u> One or more steam generators with less than two MSSVs OPERABLE.	B.1 Be in MODE 3. <u>AND</u> B.2 Be in MODE 4.	6 hours 12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.1.1	------------------NOTE------------------ Only required to be performed in MODES 1 and 2. -- Verify each required MSSV lift setpoint per Table 3.7.1-2 in accordance with the Inservice Testing Program. Following testing, lift setting shall be within ±1%.	In accordance with the Inservice Testing Program

Table 3.7.1-1 (page 1 of 1)
OPERABLE Main Steam Safety Valves versus
Applicable Neutron Flux Trip Setpoint in Percent of RATED THERMAL POWER

MINIMUM NUMBER OF MSSVs PER STEAM GENERATOR REQUIRED OPERABLE	APPLICABLE Neutron Flux Trip Setpoint (% RTP)
5	≤ 109
4	≤ 61
3	≤ 42
2	≤ 23

Table 3.7.1-2 (page 1 of 1)
Main Steam Safety Valve Lift Settings

VALVE NUMBER				LIFT SETTING (psig ± 3%)
STEAM GENERATOR				
#31	#32	#33	#34	
MS-45-1	MS-45-2	MS-45-3	MS-45-4	1065
MS-46-1	MS-46-2	MS-46-3	MS-45-4	1080
MS-47-1	MS-47-2	MS-47-3	MS-47-4	1095
MS-48-1	MS-48-2	MS-48-3	MS-48-4	1110
MS-49-1	MS-49-2	MS-49-3	MS-49-4	1120

3.7 PLANT SYSTEMS

3.7.2 Main Steam Isolation Valves (MSIVs) and Main Steam Check Valves (MSCVs)

LCO 3.7.2 Four MSIVs and four MSCVs shall be OPERABLE.

APPLICABILITY: MODE 1,
MODES 2 and 3 except when all MSIVs are closed.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more MSCVs inoperable.	A.1 Restore MSCVs to OPERABLE status.	48 hours
B. Required Action and associated Completion Time of Condition A not met.	B.1 Be in MODE 2.	6 hours
	AND	
	B.2 Close all MSIVs.	14 hours
	AND	
	B.3 Verify all MSIVs closed.	Once per 7 days
C. One MSIV inoperable in MODE 1.	C.1 Restore MSIV to OPERABLE status.	48 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Required Action and associated Completion Time of Condition C not met.	D.1 Be in MODE 2.	6 hours
E. ---------NOTE---------- Separate Condition entry is allowed for each MSIV. --------------------- One or more MSIVs inoperable in MODE 2 or 3.	E.1 Close MSIV. <u>AND</u> E.2 Verify MSIV is closed.	8 hours Once per 7 days
F. One MSIV inoperable. <u>AND</u> One or more MSCVs inoperable.	F.1 Restore all MSCVs to OPERABLE status. <u>OR</u> F.2 Restore all MSIVs to OPERABLE status.	8 hours 8 hours
G. Required Action and associated Completion Time of Condition B, E or F not met.	G.1 Be in MODE 3. <u>AND</u> G.2 Be in MODE 4.	6 hours 12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.2.1	-------------------NOTE------------------- Only required to be performed in MODES 1 and 2. -- Verify closure time of each MSIV is $\leq$ 5.0 seconds on an actual or simulated actuation signal.	In accordance with the Inservice Testing Program
SR 3.7.2.2	Perform visual inspection of each MSCV.	In accordance with the Inservice Testing Program

3.7 PLANT SYSTEMS

3.7.3 Main Boiler Feedpump Discharge Valves (MBFPDVs), Main Feedwater Regulation Valves (MBFRVs) and MBFRV Low Flow Bypass Valves

LCO 3.7.3 Two MBFPDVs, four MBFRVs and four MBFRV low flow bypass valves shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3 except when MBFPDVs, or MBFRVs and MBFRV low flow bypass valves are closed and de-activated or isolated by a closed manual valve.

ACTIONS

------------------------------------NOTE------------------------------------
Separate Condition entry is allowed for each valve.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or both MBFPDVs inoperable.	A.1 Close or isolate MBFPDV.	72 hours
	<u>AND</u>	
	A.2 Verify MBFPDV is closed or isolated.	Once per 7 days
B. One or more MBFRVs inoperable.	B.1 Close or isolate MBFRV.	72 hours
	<u>AND</u>	
	B.2 Verify MBFRV is closed or isolated.	Once per 7 days

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. One or more MBFRV low flow bypass valves inoperable.	C.1	Close or isolate bypass valve.	72 hours
	<u>AND</u>		
	C.2	Verify bypass valve is closed or isolated.	Once per 7 days
D. Two valves in series in the same flow path inoperable.	D.1	Isolate affected flow path.	8 hours
E. Required Action and associated Completion Time not met.	E.1	Be in MODE 3.	6 hours
	<u>AND</u>		
	E.2	Be in MODE 4.	12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.3.1	Verify each MBFPDV, MBFRV and MBFRV low flow bypass valve closes on an actual or simulated actuation signal within the following limits: a. MBFPDV closure time ≤ 122 seconds; b. MBFRV closure time ≤ 10 seconds; and, c. MBFRV Low Flow Bypass valve closure time ≤ 10 seconds.	In accordance with the Inservice Testing Program

3.7 PLANT SYSTEMS

3.7.4 Atmospheric Dump Valves (ADVs)

LCO 3.7.4 Three ADV lines shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3,
MODE 4 when steam generator is relied upon for heat removal.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One required ADV line inoperable.	A.1	---------NOTE--------- LCO 3.0.4 is not applicable. ---------------------- Restore required ADV line to OPERABLE status.	7 days
B. Two or more required ADV lines inoperable.	B.1	Restore all but one ADV line to OPERABLE status.	24 hours
C. Required Action and associated Completion Time not met.	C.1	Be in MODE 3.	6 hours
	<u>AND</u>		
	C.2	Be in MODE 4 without reliance upon steam generator for heat removal.	18 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.4.1	Verify one complete cycle of each ADV.	24 months
SR 3.7.4.2	Verify one complete cycle of each ADV block valve.	24 months

3.7 PLANT SYSTEMS

3.7.5 Auxiliary Feedwater (AFW) System

LCO 3.7.5 Three AFW trains shall be OPERABLE.

------------------------------NOTE------------------------------
Only one AFW train, which includes a motor driven pump capable of supporting the credited steam generator, is required to be OPERABLE in MODE 4.

APPLICABILITY: MODES 1, 2, and 3,
MODE 4 when steam generator is relied upon for heat removal.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One steam supply to turbine driven AFW pump inoperable.	A.1 Restore steam supply to OPERABLE status.	7 days AND 10 days from discovery of failure to meet the LCO
B. One AFW train inoperable in MODE 1, 2 or 3 for reasons other than Condition A.	B.1 Restore AFW train to OPERABLE status.	72 hours AND 10 days from discovery of failure to meet the LCO

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Required Action and associated Completion Time for Condition A or B not met. OR Two AFW trains inoperable in MODE 1, 2, or 3.	C.1 Be in MODE 3. AND C.2 Be in MODE 4.	6 hours 18 hours
D. Three AFW trains inoperable in MODE 1, 2, or 3.	-------------NOTE------------- LCO 3.0.3 and all other LCO Required Actions requiring MODE changes are suspended until one AFW train is restored to OPERABLE status. ------------------------------ D.1 Initiate action to restore one AFW train to OPERABLE status.	 Immediately
E. Required AFW train inoperable in MODE 4.	E.1 Initiate action to restore AFW train to OPERABLE status.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.5.1	--------------------NOTE-------------------- Not applicable in MODE 4 when steam generator is relied upon for heat removal. -- Verify each AFW manual, power operated, and automatic valve in each water flow path, and in both steam supply flow paths to the steam turbine driven pump, that is not locked, sealed, or otherwise secured in position, is in the correct position.	31 days
SR 3.7.5.2	--------------------NOTE-------------------- Not required to be performed for the turbine driven AFW pump until 24 hours after ≥ 600 psig in the steam generator. -- Verify the developed head of each AFW pump at the flow test point is greater than or equal to the required developed head.	In accordance with Inservice Testing Program
SR 3.7.5.3	--------------------NOTE-------------------- Not applicable in MODE 4 when steam generator is relied upon for heat removal. -- Verify each AFW automatic valve that is not locked, sealed, or otherwise secured in position, actuates to the correct position on an actual or simulated actuation signal.	24 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.7.5.4	----------NOTES---------- 1. Not required to be performed for the turbine driven AFW pump until 24 hours after ≥ 600 psig in the steam generator. 2. Not applicable in MODE 4 when steamgenerator is relied upon for heat removal. ------------------------------- Verify each AFW pump starts automatically on an actual or simulated actuation signal.	24 months

3.7 PLANT SYSTEMS

3.7.6 Condensate Storage Tank (CST)

LCO 3.7.6 The CST shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3,
MODE 4 when steam generator is relied upon for heat removal.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. CST inoperable.	A.1 Verify by administrative means OPERABILITY of backup water supply. AND A.2 Restore CST to OPERABLE.	Immediately AND Once per 12 hours thereafter 7 days
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 4, without reliance on steam generator for heat removal.	6 hours 18 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.6.1	Verify the CST level is ≥ 360,000 gal.	12 hours

3.7 PLANT SYSTEMS

3.7.7 City Water (CW)

LCO 3.7.7 CW shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3,
MODE 4 when steam generator is relied upon for heat removal.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. CW inoperable.	A.1	Verify by administrative means OPERABILITY of Condensate Storage Tank.	Immediately <u>AND</u> Once per 12 hours thereafter
	<u>AND</u>		
	A.2	Restore CW to OPERABLE.	7 days
B. Required Action and associated Completion Time not met.	B.1	Be in MODE 3.	6 hours
	<u>AND</u>		
	B.2	Be in MODE 4, without reliance on steam generators for heat removal.	18 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.7.1	Verify the CW header pressure is ≥ 30 psig.	12 hours
SR 3.7.7.2	Verify the Unit 3 City Water Header Supply Isolation Valve is open.	31 days
SR 3.7.7.3	Perform testing required by Inservice Testing Program for each valve needed to align CW to each AFW pump suction.	In accordance with the Inservice Testing Program

3.7 PLANT SYSTEMS

3.7.8 Component Cooling Water (CCW) System

LCO 3.7.8 Two CCW loops shall be OPERABLE.

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

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One CCW loop inoperable.	A.1	---------NOTE--------- Enter applicable Conditions and Required Actions of LCO 3.4.6, "RCS Loops - MODE 4," for residual heat removal loops made inoperable by CCW. ---------------------- Restore CCW loop to OPERABLE status.	72 hours
B. Required Action and associated Completion Time of Condition A not met.	B.1	Be in MODE 3.	6 hours
	<u>AND</u>		
	B.2	Be in MODE 5.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.8.1	-------------------NOTE------------------- Isolation of CCW flow to individual components does not render the CCW System inoperable. -- Verify each CCW manual, power operated, and automatic valve in the flow path servicing safety related equipment, that is not locked, sealed, or otherwise secured in position, is in the correct position.	92 days
SR 3.7.8.2	Verify each CCW automatic valve in the flow path that is not locked, sealed, or otherwise secured in position, actuates to the correct position on an actual or simulated actuation signal.	24 months
SR 3.7.8.3	Verify each CCW pump starts automatically on an actual or simulated actuation signal.	24 months

3.7 PLANT SYSTEMS

3.7.9 Service Water System (SW)

LCO 3.7.9 Three pumps and required flow path for the essential SW header shall be Operable;

<u>AND</u>,

Two pumps and required flow path for the nonessential SW header shall be Operable.

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

------------------------------------NOTES------------------------------------

1. Separate Condition entry is allowed for each SW header.

2. If LCO 3.7.9 will be met after the essential and non-essential header are swapped, then LCO 3.0.3 is not applicable for 8 hours while swapping the essential SW header with the nonessential SW header.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required SW pump on essential header inoperable; <u>OR</u> One required SW pump on nonessential header inoperable.	A.1 Restore SW pump to OPERABLE status.	72 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. One SW to EDG ESFAS valve inoperable.	B.1	Restore both SW to EDG ESFAS valves to OPERABLE status.	12 hours
C. One SW to FCU ESFAS valve inoperable.	C.1	Restore both SW to FCU ESFAS valves to OPERABLE status.	12 hours
D. Required Action and associated Completion Time of Condition A or B or C not met.	D.1	Be in MODE 3	6 hours
	<u>AND</u>		
	D.2	Be in MODE 5.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.9.1	-------------------NOTE------------------- Isolation of SW flow to individual components does not render the SW header inoperable. -- Verify each SW manual, power operated, and automatic valve in the flow path servicing safety related equipment, that is not locked, sealed, or otherwise secured in position, is in the correct position.	92 days
SR 3.7.9.2	Verify each SW automatic valve in the flow path that is not locked, sealed, or otherwise secured in position, actuates to the correct position on an actual or simulated actuation signal.	24 months
SR 3.7.9.3	Verify each SW pump starts automatically on an actual or simulated actuation signal.	24 months

3.7 PLANT SYSTEMS

3.7.10 Ultimate Heat Sink (UHS)

LCO 3.7.10 The UHS shall be OPERABLE.

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

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. UHS temperature > 95°F.	A.1 Verify UHS temperature ≤ 95°F.	7 hours
B. Required Action and associated Completion Time of Condition A not met. OR UHS inoperable for reasons other than Condition A.	B.1 Be in MODE 3. AND B.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.10.1	Verify average water temperature of UHS is ≤ 95°F.	24 hours

3.7 PLANT SYSTEMS

3.7.11 Control Room Ventilation System (CRVS)

LCO 3.7.11 Two CRVS trains shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, 4.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One CRVS train inoperable.	A.1 Restore CRVS train to OPERABLE status.	7 days
B. Two CRVS trains inoperable.	B.1 Restore one CRVS train to OPERABLE status.	72 hours
C. Required Action and associated Completion Time of Condition A or B not met.	C.1 Be in MODE 3. AND C.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.11.1	Operate each CRVS train for ≥ 15 minutes.	31 days
SR 3.7.11.2	Perform required CRVS filter testing in accordance with the Ventilation Filter Testing Program (VFTP).	In accordance with VFTP
SR 3.7.11.3	Verify each CRVS train actuates on an actual or simulated actuation signal.	24 months
SR 3.7.11.4	Verify one CRVS train can maintain a slight positive pressure relative to the adjacent enclosed area during the 10% incident mode of operation at a makeup flow rate of ≤ 400 cfm.	24 months on a STAGGERED TEST BASIS

3.7 PLANT SYSTEMS

3.7.12 Control Room Air Conditioning System (CRACS)

LCO 3.7.12 Two CRACS trains shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3 and 4,

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One CRACS train inoperable.	A.1 Restore CRACS train to OPERABLE status.	30 days
B. Two CRACS trains inoperable.	B.1 Restore one CRACS train to OPERABLE status.	72 hours
C. Required Action and associated Completion Time of Condition A or B not met.	C.1 Be in MODE 3. <u>AND</u> C.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.7.12.1 Verify each CRACS train has the capability to remove the assumed heat load.	24 months

3.7 PLANT SYSTEMS

3.7.13 Fuel Storage Building Emergency Ventilation System (FSBEVS)

LCO 3.7.13 FSBEVS shall be OPERABLE.

APPLICABILITY: During movement of irradiated fuel assemblies in the fuel storage building.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. FSBEVS inoperable.	A.1 Suspend movement of irradiated fuel assemblies in the fuel storage building.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.13.1	Verify FSBEVS charcoal filter bypass dampers are installed.	92 days
SR 3.7.13.2	Operate FSBEVS for ≥ 15 minutes.	31 days
SR 3.7.13.3	Perform required FSBEVS filter testing in accordance with the Ventilation Filter Testing Program (VFTP).	In accordance with the VFTP
SR 3.7.13.4	Verify FSBEVS actuates on an actual or simulated actuation signal.	92 days
SR 3.7.13.5	Verify FSBEVS can maintain a pressure ≤ -0.125 inches water gauge with respect to atmospheric pressure during the post accident mode of operation at a flow rate ≤ 20,000 cfm.	24 months

3.7 PLANT SYSTEMS

3.7.14 Spent Fuel Pit Water Level

LCO 3.7.14 The spent fuel pit water level shall be ≥ 23 ft over the top of irradiated fuel assemblies seated in the storage racks.

APPLICABILITY: During movement of irradiated fuel assemblies in the spent fuel pit.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. Spent fuel pit water level not within limit.	A.1	---------NOTE--------- LCO 3.0.3 is not applicable. --------------------- Suspend movement of irradiated fuel assemblies in the spent fuel pit.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.14.1	Verify the spent fuel pit water level is ≥ 23 ft above the top of the irradiated fuel assemblies seated in the storage racks.	7 days

3.7 PLANT SYSTEMS

3.7.15 Spent Fuel Pit Boron Concentration

LCO 3.7.15 The Spent Fuel Pit boron concentration shall be ≥ 1000 ppm.

APPLICABILITY: When fuel assemblies are stored in the spent fuel pit and a spent fuel pit verification has not been performed since the last movement of fuel assemblies in the spent fuel pit.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Spent fuel pit boron concentration not within limit.	-------------NOTE------------- LCO 3.0.3 is not applicable. ------------------------------	
	A.1 Suspend movement of fuel assemblies in the spent fuel pit.	Immediately
	<u>AND</u>	
	A.2.1 Initiate action to restore spent fuel pit boron concentration to within limit.	Immediately
	<u>OR</u>	
	A.2.2 Initiate action to perform a spent fuel pit verification.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.15.1	Verify the spent fuel pit boron concentration is within limit.	7 days

3.7 PLANT SYSTEMS

3.7.16 Spent Fuel Assembly Storage

LCO 3.7.16

Fuel assemblies stored in the spent fuel pit shall be classified in accordance with Figure 3.7.16-1 based on initial enrichment and burnup; and,

Fuel assembly storage location within the spent fuel pit shall be restricted based on the Figure 3.7.16-1 classification as follows:

a. Fuel assemblies classified as Type 2 may be stored in any location in either Region 1 or Region 2;

b. Fuel assemblies classified as Type 1A, 1B or 1C shall be stored in Region 1;

c. Fuel assembly storage location within Region 1 shall be restricted as follows:

1. Type 1A assemblies may be stored anywhere in Region 1;

2. Type 1B assemblies may be stored anywhere in Region 1, except a Type 1B assembly shall not be stored face-adjacent to a Type 1C assembly;

3. Type 1C assemblies shall not be stored in Row 64 or in Column ZZ; and

4. Type 1C assemblies shall be stored in Region 1 locations where all face-adjacent locations are as follows:

a) occupied by Type 2 or Type 1A assemblies, or

b) occupied by non-fuel components, or

c) empty.

APPLICABILITY: Whenever any fuel assembly is stored in the spent fuel pit.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Requirements of the LCO not met.	A.1 ---------NOTE---------- LCO 3.0.3 is not applicable. --------------------- Initiate action to move fuel to restore compliance with LCO 3.7.16.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.16.1	Verify by administrative means the initial enrichment and burnup of each fuel assembly and that the storage location meets LCO 3.7.16 requirements.	Prior to storing the fuel assembly in the spent fuel pit

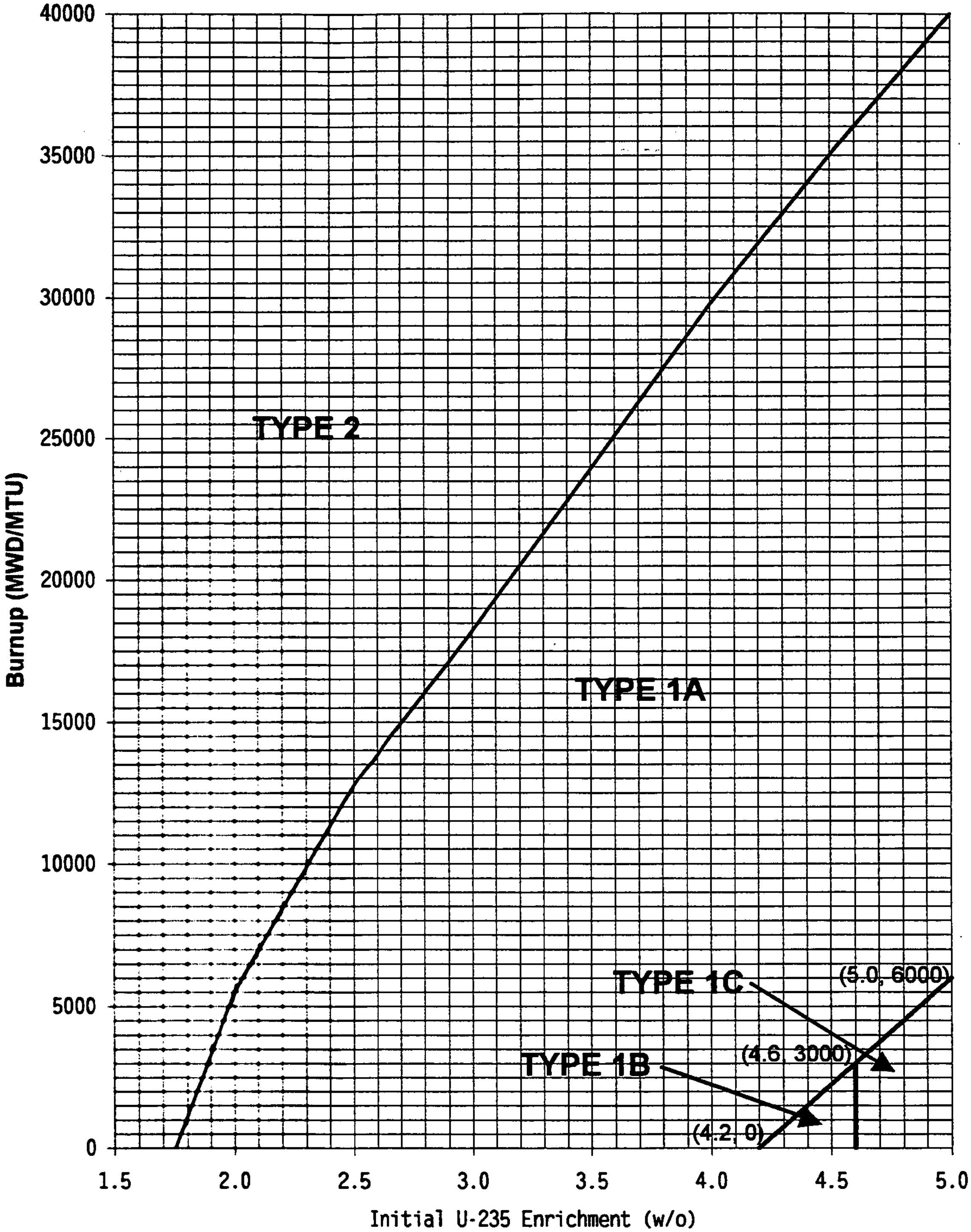

Figure 3.7.16-1 (Page 1 of 1)
Fuel Assembly Classification
for Storage in the Spent Fuel Pit

3.7 PLANT SYSTEMS

3.7.17 Secondary Specific Activity

LCO 3.7.17 The specific activity of the secondary coolant shall be $\leq$ 0.10 μCi/gm DOSE EQUIVALENT I-131.

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

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Specific activity not within limit.	A.1 Be in MODE 3.	6 hours
	AND	
	A.2 Be in MODE 5.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.7.17.1 Verify the specific activity of the secondary coolant is $\leq$ 0.10 μCi/gm DOSE EQUIVALENT I-131.	31 days

3.8 ELECTRICAL POWER SYSTEMS

3.8.1 AC Sources – Operating

LCO 3.8.1 The following AC electrical sources shall be OPERABLE:

a. Two qualified circuits between the offsite transmission network and the onsite Electrical Power Distribution System; and

b. Three diesel generators (DGs) (31, 32 and 33) capable of supplying the onsite power distribution subsystem(s)

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

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One offsite circuit inoperable.	A.1 Perform SR 3.8.1.1 for OPERABLE offsite circuit. AND	1 hour AND Once per 8 hours thereafter
		(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. (continued)		---------NOTE----------- Only required if 13.8 kV offsite circuit is supplying 6.9 kV bus 5 or 6 and the Unit Auxiliary Transformer is supplying 6.9 kV bus 2 or 3. ------------------------	
	A.2	Verify automatic transfer of 6.9 kV buses 1, 2, 3, and 4 to 6.9 kV bus 5 and 6 is disabled.	1 hour AND Once per 8 hours thereafter
	AND		
	A.3	Declare inoperable required feature(s) with no offsite power available when its redundant required feature(s) is inoperable.	24 hours from discovery of no available offsite power to one train concurrent with inoperability of redundant required feature(s)
	AND		
	A.4	Restore offsite circuit to OPERABLE status.	72 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. One DG inoperable.	B.1	Perform SR 3.8.1.1 for the offsite circuits.	1 hour AND Once per 8 hours thereafter
	AND		
	B.2	Declare inoperable the required features supported by the inoperable DG when its required redundant feature is inoperable.	4 hours from discovery of Condition B concurrent with inoperability of redundant required feature
	AND		
	B.3.1	Determine OPERABLE DG(s) are not inoperable due to common cause failure. OR	24 hours
	B.3.2	Perform SR 3.8.1.2 for OPERABLE DGs.	24 hours
	AND		
	B.4	Restore DG to OPERABLE status.	72 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Two offsite circuits inoperable.	C.1 Declare required features inoperable when its redundant required feature is inoperable.	12 hours from discovery of Condition C concurrent with inoperability of redundant required feature
	AND	
	C.2 Restore one offsite circuit to OPERABLE status.	24 hours
D. One offsite circuit inoperable. AND One DG inoperable.	-----------NOTE--------- Enter applicable Conditions and Required Actions of LCO 3.8.9, "Distribution Systems – Operating," when Condition D is entered with no offsite or DG AC power source to any train. ------------------------	
	D.1 Restore offsite circuit to OPERABLE status.	12 hours
	OR	
	D.2 Restore DG to OPERABLE status.	12 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. Two or more DGs inoperable.	E.1 Restore at least two DGs to OPERABLE status.	2 hours
F. Required Action and associated Completion Time of Condition A, B, C, D, or E not met.	F.1 Be in MODE 3. AND F.2 Be in MODE 5.	6 hours 36 hours
G. One or more offsite circuits and two DGs inoperable.	G.1 Enter LCO 3.0.3.	Immediately
H. Two offsite circuits and one or more DGs inoperable.	H.1 Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.1.1	Verify correct breaker alignment and indicated power availability for each offsite circuit.	7 days
SR 3.8.1.2	--------------------NOTE-------------------- All DG starts may be preceded by an engine prelube period. -- Verify each DG starts from standby conditions and achieves in ≤ 10 seconds, voltage ≥ 422 V and ≤ 500 V, and frequency ≥ 58.8 Hz and ≤ 61.2 Hz.	 31 days
SR 3.8.1.3	--------------------NOTES------------------- 1. DG loadings may include gradual loading as recommended by the manufacturer. 2. Momentary transients outside the load range do not invalidate this test. 3. This SR shall be conducted on only one DG at a time. 4. This SR shall be preceded by and immediately follow without shutdown a successful performance of SR 3.8.1.2. -- Verify each DG is synchronized and loaded and operates for ≥ 60 minutes at a load ≥ 1575 kW and ≤ 1750 kW.	 31 days

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.4	Verify each day tank contains ≥ 115 gal of fuel oil.	31 days
SR 3.8.1.5	Check for and remove accumulated water from each day tank.	31 days
SR 3.8.1.6	Verify the fuel oil transfer system operates to automatically transfer fuel oil from DG storage tank to the day tank.	31 days
SR 3.8.1.7	Verify manual transfer of AC power sources from the normal offsite circuit to the alternate offsite circuit.	24 months
SR 3.8.1.8	-------------------NOTES-------------------- 1. This Surveillance shall not be performed in MODE 1 or 2. 2. Only required to be met if 138 kV offsite circuit is supplying 6.9 kV bus 5 and 6 and the Unit Auxiliary Transformer is supplying 6.9 kV bus 2 or 3. --- Verify automatic transfer of AC power for 6.9 kV buses 2 and 3 from the unit auxiliary transformer to 6.9 kV buses 5 and 6.	24 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.9	Verify each DG's automatic trips are bypassed on actual or simulated loss of voltage signal on the emergency bus concurrent with an actual or simulated ESF actuation signal except: a. Engine overspeed; b. Low lube oil pressure; and c. Overcrank relay.	24 months
SR 3.8.1.10	-------------------NOTE-------------------- Momentary transients outside the load and power factor ranges do not invalidate this test. --- Verify each DG operating at a power factor ≤ 0.9 operates for ≥ 8 hours: a. For ≥ 105 minutes loaded ≥ 1837 kW and ≤ 1925 kW; and b. For the remaining hours of the test loaded ≥ 1575 kW and ≤ 1750 kW.	24 months
SR 3.8.1.11	-----------------NOTE---------------------- Load timers associated with equipment that has automatic initiation capability disabled are not required to be operable. --- Verify each time delay relay functions within the required design interval.	18 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.12	------------------NOTES------------------ 1. All DG starts may be preceded by an engine prelube period. 2. This Surveillance shall not be performed in MODE 1, 2, 3, or 4. 3. This SR may be performed on one safeguards power train or on two or three safeguards power trains simultaneously. -- Verify on an actual or simulated loss of offsite power signal in conjunction with an actual or simulated ESF actuation signal: a. De-energization of emergency buses; b. Load shedding from emergency buses; and c. DG auto-starts from standby condition and: 1. energizes permanently connected loads in ≤ 10 seconds, 2. energizes auto-connected emergency loads through individual load timers, 3. achieves steady state voltage ≥ 422 V and ≤ 500 V, 4. achieves steady state frequency ≥ 58.8 Hz and ≤ 61.2 Hz, and 5. supplies permanently connected and auto-connected emergency loads for ≥ 5 minutes.	24 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.8.1.13	------------------NOTE------------------ 1. All DG starts may be preceded by an engine prelube period. 2. Performance of SR 3.8.1.12 may be used to satisfy the requirements of this SR if all three diesel generators are started simultaneously. -- Verify when started simultaneously from standby condition, each DG achieves, in ≤ 10 seconds, voltage ≥ 422 V and ≤ 500 V, and frequency ≥ 58.8 Hz and ≤ 61.2 Hz.	10 years

3.8 ELECTRICAL POWER SYSTEMS

3.8.2 AC Sources – Shutdown

LCO 3.8.2 The following AC electrical power sources shall be OPERABLE:

a. One qualified circuit between the offsite transmission network and the onsite AC electrical power distribution subsystem(s) required by LCO 3.8.10, "Distribution Systems – Shutdown"; and

b. Two diesel generators (DGs) capable of supplying two safeguards power trains of the onsite AC electrical power distribution subsystem(s) required by LCO 3.8.10.

APPLICABILITY: MODES 5 and 6,
During movement of irradiated fuel assemblies.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required offsite circuit inoperable.	------------NOTE------------ Enter applicable Conditions and Required Actions of LCO 3.8.10, with any required bus de-energized as a result of Condition A. ------------------------------	
	A.1 Declare affected required feature(s) with no offsite power available inoperable.	Immediately
	OR	
		(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (Continued)	A.2.1 Suspend CORE ALTERATIONS.	Immediately
	AND	
	A.2.2 Suspend movement of irradiated fuel assemblies.	Immediately
	AND	
	A.2.3 Initiate action to suspend operations involving positive reactivity additions.	Immediately
	AND	
	A.2.4 Initiate action to restore required offsite power circuit to OPERABLE status.	Immediately
B. One or more required DGs inoperable.	B.1 Declare affected required feature(s) with no DG available inoperable.	Immediately
	OR	
	B.2.1 Suspend CORE ALTERATIONS.	Immediately
	AND	
		(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. (continued)	B.2.2	Suspend movement of irradiated fuel assemblies.	Immediately
	<u>AND</u>		
	B.2.3	Initiate action to suspend operations involving positive reactivity additions.	Immediately
	<u>AND</u>		
	B.2.4	Initiate action to restore required DG(s) to OPERABLE status.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.2.1	------------------NOTE------------------ The following SRs are required to be met but are not required to be performed: SR 3.8.1.3, SR 3.8.1.8, SR 3.8.1.9, SR 3.8.1.10, SR 3.8.1.11, SR 3.8.1.12; and SR 3.8.1.13. -- For AC sources required to be OPERABLE, the SRs of Specification 3.8.1, "AC Sources – Operating," are applicable.	In accordance with applicable SRs

3.8 ELECTRICAL POWER SYSTEMS

3.8.3 Diesel Fuel Oil and Starting Air

LCO 3.8.3 The stored diesel fuel oil and starting air subsystem shall be within limits for each required diesel generator (DG).

APPLICABILITY: When associated DG is required to be OPERABLE.

ACTIONS

------------------------------------NOTE------------------------------------
Separate Condition entry is allowed for each DG.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. ----------NOTE---------- Only applicable in MODES 1, 2, 3 and 4. ---------------------- One or more DGs with usable fuel oil in associated DG fuel oil storage tank < 5891 gal.	A.1 Declare associated DG inoperable.	Immediately
B. ----------NOTE---------- Only applicable in MODES 5 and 6 and during movement of irradiated fuel. ---------------------- Total usable fuel oil in all DG fuel oil storage tanks < 5891 gal.	B.1 Declare all DGs inoperable.	Immediately

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. ---------NOTE---------- Only applicable in MODES 1, 2, 3 and 4. ---------------------- Total useable fuel oil in reserve storage tank(s) < 30,026 gal.	C.1	Declare all DGs inoperable.	Immediately
D. One or more DG fuel oil storage tanks with fuel oil total particulates not within limits.	D.1	Restore stored fuel oil total particulates within limits of SR 3.8.3.3.	7 days
E. One or more DG fuel oil storage tanks with new fuel oil properties not within limits.	E.1	Restore stored fuel oil properties to within limits of SR 3.8.3.3.	30 days
F. Fuel oil in reserve storage tank(s) with properties not within limits of SR 3.8.3.4.	F.1	Restore fuel oil in reserve storage tank(s) to within limits of SR 3.8.3.4.	30 days
G. One or more DGs with starting air receiver pressure < 250 psig and ≥ 90 psig.	G.1	Restore starting air receiver pressure to ≥ 250 psig.	48 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
H. Required Action and associated Completion Time not met. OR One or more DGs diesel fuel oil or starting air subsystem not within limits for reasons other than Condition A, B, C, D, E, F or G.	H.1 Declare associated DG inoperable.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.3.1	-------------------NOTE-------------------- Only required in MODES 1, 2, 3 and 4. -- Verify reserve storage tank(s) contain ≥ 30,026 gal of fuel oil reserved for IP3 usage only.	24 hours
SR 3.8.3.2	Verify DG fuel oil storage tanks contain: a. Usable fuel oil volume ≥ 5891 gal in each storage tank when in MODES 1, 2, 3 and 4; and b. Total usable fuel oil volume ≥ 5891 gal in storage tank(s) when in MODES 5 and 6 and during movement of irradiated fuel assemblies.	31 days
SR 3.8.3.3	Verify that fuel oil properties of new and stored fuel oil in the DG fuel oil storage tanks are tested and maintained in accordance with the Diesel Fuel Oil Testing Program.	In accordance with the Diesel Fuel Oil Testing Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.3.4	--------------------NOTE-------------------- Only required in MODES 1, 2, 3 and 4. -- Verify that fuel oil properties in the reserve storage tank(s) are within limits specified in the Diesel Fuel Oil Testing Program.	In accordance with the Diesel Fuel Oil Testing Program
SR 3.8.3.5	Verify each DG air start receiver pressure is ≥ 250 psig.	31 days
SR 3.8.3.6	Check for and remove accumulated water from each DG fuel oil storage tank.	92 days

3.8 ELECTRICAL POWER SYSTEMS

3.8.4 DC Sources – Operating

LCO 3.8.4 The following four DC electrical power subsystems shall be OPERABLE:

Battery 31 and associated Battery Charger;
Battery 32 and associated Battery Charger;
Battery 33 and associated Battery Charger; and
Battery 34.

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

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. DC electrical power subsystem 34 inoperable.	A.1	Declare Inverter 34 inoperable and take Required Actions specified in LCO 3.8.7, Inverters-Operating.	2 hours
B. One DC electrical power subsystem (31 or 32 or 33) inoperable.	B.1	Restore DC electrical power subsystem to OPERABLE status.	2 hours
C. Required Action and Associated Completion Time not met.	C.1	Be in MODE 3.	6 hours
	<u>AND</u>		
	C.2	Be in MODE 5.	36 hours

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.8.4.1	Verify battery terminal voltage on float charge is within the following limits: a. ≥ 120.06 V for batteries 31 and 32; and b. ≥ 124.20 V for batteries 33 and 34.	31 days
SR 3.8.4.2	-------------------NOTE------------------- This Surveillance shall not be performed in MODE 1, 2, 3, or 4. -- Verify each battery charger supplies its associated battery at the voltage and current adequate to demonstrate battery charger capability requirements are met.	24 months
SR 3.8.4.3	-------------------NOTES------------------- This Surveillance shall not be performed in MODE 1, 2, 3, or 4. -- Verify battery capacity is adequate to supply, and maintain in OPERABLE status, the required emergency loads for the design duty cycle when subjected to a battery service test or a modified performance discharge test.	24 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.4.4	-------------------NOTE------------------- This Surveillance shall not be performed in MODE 1, 2, 3, or 4. -- Verify battery capacity is ≥ 80% of the manufacturer's rating when subjected to a performance discharge test or a modified performance discharge test.	60 months AND 12 months when battery shows degradation or has reached 85% of expected life with capacity < 100% of manufacturer's rating AND 24 months when battery has reached 85% of the expected life with capacity ≥ 100% of manufacturer's rating

3.8 ELECTRICAL POWER SYSTEMS

3.8.5 DC Sources – Shutdown

LCO 3.8.5 DC electrical power subsystems shall be OPERABLE to support the DC electrical power distribution subsystems required by LCO 3.8.10, "Distribution Systems – Shutdown."

APPLICABILITY: MODES 5 and 6,
During movement of irradiated fuel assemblies.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required DC electrical power subsystems inoperable.	A.1 Declare affected required feature(s) inoperable.	Immediately
	OR	
	A.2.1 Suspend CORE ALTERATIONS.	Immediately
	AND	
	A.2.2 Suspend movement of irradiated fuel assemblies.	Immediately
	AND	
	A.2.3 Initiate action to suspend operations involving positive reactivity additions.	Immediately
	AND	
		(continued)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. (continued)	A.2.4	Initiate action to restore required DC electrical power subsystems to OPERABLE status.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.5.1	-------------------NOTE------------------- The following SRs are not required to be performed: SR 3.8.4.2, SR 3.8.4.3, and SR 3.8.4.4. -- For DC sources required to be OPERABLE, the following SRs are applicable: SR 3.8.4.1 SR 3.8.4.3 SR 3.8.4.2 SR 3.8.4.4.	In accordance with applicable SRs

3.8 ELECTRICAL POWER SYSTEMS

3.8.6 Battery Cell Parameters

LCO 3.8.6 Battery cell parameters for batteries 31, 32, 33 and 34 shall be within the limits of Table 3.8.6-1.

APPLICABILITY: When associated DC electrical power subsystems are required to be OPERABLE.

ACTIONS

------------------------------------NOTE------------------------------------

Separate Condition entry is allowed for each battery.

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or more batteries with one or more battery cell parameters not within Category A or B limits.	A.1	Verify pilot cells electrolyte level and float voltage meet Table 3.8.6-1 Category C limits.	1 hour
	<u>AND</u>		
	A.2	Verify battery cell parameters meet Table 3.8.6-1 Category C limits.	24 hours <u>AND</u> Once per 7 days thereafter
	<u>AND</u>		
	A.3	Restore battery cell parameters to Category A and B limits of Table 3.8.6-1.	31 days

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Required Action and associated Completion Time of Condition A not met. OR One or more batteries with average electrolyte temperature of the representative cells not within limits of SR 3.8.6.3. OR One or more batteries with one or more battery cell parameters not within Category C values.	B.1 Declare associated battery inoperable.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.6.1	Verify battery cell parameters meet Table 3.8.6-1 Category A limits.	31 days
SR 3.8.6.2	Verify battery cell parameters meet Table 3.8.6-1 Category B limits.	92 days
SR 3.8.6.3	Verify average electrolyte temperature of representative cells is within the following limits: a. ≥ 60°F for batteries 31, 32 and 34; and b. ≥ 35°F for battery 33.	92 days

Table 3.8.6-1 (page 1 of 1)
Battery Cell Parameters Requirements

PARAMETER	CATEGORY A: LIMITS FOR EACH DESIGNATED PILOT CELL	CATEGORY B: LIMITS FOR EACH CONNECTED CELL	CATEGORY C: ALLOWABLE LIMITS FOR EACH CONNECTED CELL
Electrolyte Level	> Minimum level indication mark, and ≤ ¼ inch above maximum level indication mark[(a)]	> Minimum level indication mark, and ≤ ¼ inch above maximum level indication mark[(a)]	Above top of plates, and not overflowing
Float Voltage	≥ 2.13 V	≥ 2.13 V	> 2.07 V
Specific Gravity[(b)]	≥ 1.205	≥ 1.195 AND Average of all connected cells > 1.205	Not more than 0.020 below average of all connected cells AND Average of all connected cells ≥ 1.195

(a) It is acceptable for the electrolyte level to temporarily increase above the specified maximum during equalizing charges provided it is not overflowing.

(b) Corrected for electrolyte temperature.

ACTIONS (continued)

3.8 ELECTRICAL POWER SYSTEMS

3.8.7 Inverters – Operating

LCO 3.8.7 Inverters 31, 32, 33 and 34 shall be OPERABLE; and Two constant voltage transformers (CVTs) capable of supplying 120 V AC vital instrument bus (VIB) 34 shall be OPERABLE.

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

ACTIONS

-- NOTE --

Enter applicable Conditions and Required Actions of LCO 3.8.9, "Distribution Systems - Operating" with any required bus de-energized.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required CVT inoperable.	A.1 Restore CVT to OPERABLE status.	30 days
B. Two required CVTs inoperable.	B.1 Restore one CVT to OPERABLE status.	7 days

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. One inverter inoperable.	C.1	---------NOTE--------- Only applicable to feature(s) that require power to perform the required safety function. --------------------- Declare required feature(s) supported by associated inverter inoperable when the required redundant feature(s) is inoperable.	2 hours from discovery of Condition C concurrent with inoperability of redundant required feature(s)
	<u>AND</u>		
	C.2	Restore inverter to OPERABLE status.	7 days
D. Required Action and associated Completion Time not met.	D.1	Be in MODE 3.	6 hours
	<u>AND</u>		
	D.2	Be in MODE 5.	36 hours

ACTIONS (continued)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.7.1	Verify correct inverter voltage and alignment to required 120V AC vital buses.	7 days
SR 3.8.7.2	Verify manual transfer of the AC power source for VIB 34 from inverter 34 to each required CVT.	24 months

3.8 ELECTRICAL POWER SYSTEMS

3.8.8 Inverters – Shutdown

LCO 3.8.8 Inverters shall be OPERABLE to support the onsite 120 V AC vital instrument bus (VIB) electrical power distribution subsystems required by LCO 3.8.10, "Distribution Systems – Shutdown."

APPLICABILITY: MODES 5 and 6,
During movement of irradiated fuel assemblies.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or more required inverters inoperable.	A.1	Declare affected required feature(s) inoperable.	Immediately
	<u>OR</u>		
	A.2.1	Suspend CORE ALTERATIONS.	Immediately
	<u>AND</u>		
	A.2.2	Suspend movement of irradiated fuel assemblies.	Immediately
	<u>AND</u>		
	A.2.3	Initiate action to suspend operations involving positive reactivity additions.	Immediately
	<u>AND</u>		
			(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. (continued)	A.2.4	Initiate action to restore required inverters to OPERABLE status.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.8.1	Verify correct inverter voltage and alignments to required 120 V AC vital instrument buses.	7 days

3.8 ELECTRICAL POWER SYSTEMS

3.8.9 Distribution Systems – Operating

LCO 3.8.9 AC, DC, and 120 V AC vital instrument bus VIB electrical power distribution subsystems for safeguards power trains 5A, 6A and 2A/3A shall be OPERABLE.

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

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One AC electrical power distribution subsystem inoperable with no loss of safety function.	A.1 Restore AC electrical power distribution subsystem to OPERABLE status.	8 hours <u>AND</u> 16 hours from discovery of failure to meet LCO
B. One VIB inoperable no loss of safety function.	B.1 Restore VIB to OPERABLE status.	2 hours <u>AND</u> 16 hours from discovery of failure to meet LCO

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. One DC electrical power distribution subsystem inoperable with no loss of safety function.	C.1	Restore DC electrical power distribution subsystem to OPERABLE status.	2 hours AND 16 hours from discovery of failure to meet LCO
D. Required Action and associated Completion Time not met.	D.1 AND	Be in MODE 3.	6 hours
	D.2	Be in MODE 5.	36 hours
E. One or more trains with inoperable distribution subsystems that result in a loss of safety function.	E.1	Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.9.1	Verify correct breaker alignments and voltage to required AC, DC, and VIB electrical power distribution subsystems.	7 days

3.8 ELECTRICAL POWER SYSTEMS

3.8.10 Distribution Systems – Shutdown

LCO 3.8.10 The necessary portion of AC, DC, and 120 AC vital instrument bus (VIB) electrical power distribution subsystems shall be OPERABLE to support equipment required to be OPERABLE.

APPLICABILITY: MODES 5 and 6,
During movement of irradiated fuel assemblies.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required AC, DC, or AC vital instrument bus electrical power distribution subsystems inoperable.	A.1 Declare associated supported required feature(s) inoperable.	Immediately
	<u>OR</u>	
	A.2.1 Suspend CORE ALTERATIONS.	Immediately
	<u>AND</u>	
	A.2.2 Suspend movement of irradiated fuel assemblies.	Immediately
	<u>AND</u>	
	A.2.3 Initiate action to suspend operations involving positive reactivity additions.	Immediately
	<u>AND</u>	
		(continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.2.4 Initiate actions to restore required AC, DC, and AC vital instrument bus electrical power distribution subsystems to OPERABLE status.	Immediately
	AND	
	A.2.5 Declare associated required residual heat removal subsystem(s) inoperable and not in operation.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.10.1	Verify correct breaker alignments and voltage to required AC, DC, and 120 V AC vital instrument bus (VIB) electrical power distribution subsystems.	7 days

3.9 REFUELING OPERATIONS

3.9.1 Boron Concentration

LCO 3.9.1 Boron concentrations of the Reactor Coolant System and the refueling cavity shall be maintained within the limit specified in the COLR.

APPLICABILITY: MODE 6.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Boron concentration not within limit.	A.1 Suspend CORE ALTERATIONS.	Immediately
	<u>AND</u>	
	A.2 Suspend positive reactivity additions.	Immediately
	<u>AND</u>	
	A.3 Initiate action to restore boron concentration to within limit.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.1.1	Verify boron concentration is within the limit specified in COLR.	72 hours

3.9 REFUELING OPERATIONS

3.9.2 Nuclear Instrumentation

LCO 3.9.2 Two source range neutron flux monitors shall be OPERABLE.

APPLICABILITY: MODE 6.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required source range neutron flux monitor inoperable.	A.1 Suspend CORE ALTERATIONS. AND A.2 Suspend positive reactivity additions.	Immediately Immediately
B. Two required source range neutron flux monitors inoperable.	B.1 Initiate action to restore one source range neutron flux monitor to OPERABLE status. AND B.2 Perform SR 3.9.1.1.	Immediately Once per 12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.2.1	Perform CHANNEL CHECK.	12 hours
SR 3.9.2.2	------------------NOTE------------------ Neutron detectors are excluded from CHANNEL CALIBRATION. -- Perform CHANNEL CALIBRATION.	24 months

3.9 REFUELING OPERATIONS

3.9.3 Containment Penetrations

LCO 3.9.3 The containment penetrations shall be in the following status:

a. The equipment hatch closed and held in place by at least four bolts or the equipment hatch opening is closed using an equipment hatch closure plate that may include a closed personnel access door;

b. One door in each air lock closed;

c. Each penetration providing direct access from the containment atmosphere to the outside atmosphere either:

1. closed by a manual or automatic isolation valve, a blind flange, or equivalent, or

2. capable of being closed by OPERABLE Containment Purge System isolation instrumentation.

--------------------------NOTE--------------------------

LCO 3.9.3.d and LCO 3.9.3.e are not required to be met if the reactor has been subcritical for ≥ 550 hours.

----

d. The Containment Purge System flow path shall be either:

1. closed by a manual or automatic isolation valve, a blind flange, or equivalent, or

2. aligned to discharge through the HEPA filters and charcoal adsorbers.

e. The Containment Pressure Relief Line shall be closed by a manual or automatic isolation valve, a blind flange, or equivalent.

APPLICABILITY: During CORE ALTERATIONS,
During movement of irradiated fuel assemblies within containment.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more containment penetrations not in required status.	A.1 Suspend CORE ALTERATIONS.	Immediately
	<u>AND</u>	
	A.2 Suspend movement of irradiated fuel assemblies within containment.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.3.1	Verify each required containment penetration is in the required status.	7 days
SR 3.9.3.2	----------NOTE---------- Not required to be met if the reactor has been subcritical for ≥ 550 hours. ------------------------------ Verify Containment Purge System is either: a. closed by a manual or automatic isolation valve, blind flange, or equivalent, or b. aligned to discharge through the HEPA filters and charcoal adsorbers.	7 days
SR 3.9.3.3	Verify each required containment purge system valve actuates to the isolation position on an actual or simulated actuation signal.	92 days
SR 3.9.3.4	----------NOTE---------- Not required to be met if the reactor has been subcritical for ≥ 550 hours. ------------------------------ Perform required Containment Purge System filter testing in accordance with the Ventilation Filter Testing Program (VFTP).	In accordance with the VFTP

3.9 REFUELING OPERATIONS

3.9.4 Residual Heat Removal (RHR) and Coolant Circulation – High Water Level

LCO 3.9.4 One RHR loop shall be OPERABLE and in operation.

------------------------------NOTE------------------------------
The required RHR loop may not be in operation for ≤ 1 hour per 8 hour period, provided no operations are permitted that would cause reduction of the Reactor Coolant System boron concentration.

APPLICABILITY: MODE 6 with the water level ≥ 23 ft above the top of reactor vessel flange.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. RHR loop requirements not met.	A.1	Suspend operations involving a reduction in reactor coolant boron concentration.	Immediately
	<u>AND</u>		
	A.2	Suspend loading irradiated fuel assemblies in the core.	Immediately
	<u>AND</u>		
	A.3	Initiate action to satisfy RHR loop requirements.	Immediately
	<u>AND</u>		
			(continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.4 Close all containment penetrations providing direct access from containment atmosphere to outside atmosphere.	4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR 3.9.4.1 Verify one RHR loop is in operation and circulating reactor coolant at a flow rate of ≥ 1000 gpm.	12 hours

3.9 REFUELING OPERATIONS

3.9.5 Residual Heat Removal (RHR) and Coolant Circulation – Low Water Level

LCO 3.9.5 Two RHR loops shall be OPERABLE, and one RHR loop shall be in operation.

APPLICABILITY: MODE 6 with the water level < 23 ft above the top of reactor vessel flange.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Less than the required number of RHR loops OPERABLE.	A.1 Initiate action to restore required RHR loops to OPERABLE status.	Immediately
	<u>OR</u>	
	A.2 Initiate action to establish ≥ 23 ft of water above the top of reactor vessel flange.	Immediately
B. No RHR loop in operation.	B.1 Suspend operations involving a reduction in reactor coolant boron concentration.	Immediately
	<u>AND</u>	
		(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. (continued)	B.2	Initiate action to restore one RHR loop to operation.	Immediately
	AND		
	B.3	Close all containment penetrations providing direct access from containment atmosphere to outside atmosphere.	4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.5.1	Verify one RHR loop is in operation and circulating reactor coolant at a flow rate of ≥ 1000 gpm.	12 hours
SR 3.9.5.2	Verify correct breaker alignment and indicated power available to the required RHR pump that is not in operation.	7 days

3.9 REFUELING OPERATIONS

3.9.6 Refueling Cavity Water Level

LCO 3.9.6 Refueling cavity water level shall be maintained ≥ 23 ft above the top of reactor vessel flange.

APPLICABILITY: During CORE ALTERATIONS, except during latching and unlatching of control rod drive shafts,
During movement of irradiated fuel assemblies within containment.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Refueling cavity water level not within limit.	A.1 Suspend CORE ALTERATIONS. <u>AND</u> A.2 Suspend movement of irradiated fuel assemblies within containment.	Immediately Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.9.6.1	Verify refueling cavity water level is ≥ 23 ft above the top of reactor vessel flange.	24 hours

4.0 DESIGN FEATURES

4.1 Site Location

Indian Point 3 is located on the east bank of the Hudson River at Indian Point, Village of Buchanan, in upper Westchester County, New York. The site is approximately 24 miles north of the New York City boundary line. The nearest city is Peekskill which is 2.5 miles northeast of Indian Point.

The minimum distance from the reactor center line to the boundary of the site exclusion area and the outer boundary of the low population zone as defined in 10 CFR 100.3 is 350 meters and 1100 meters, respectively.

4.2 Reactor Core

4.2.1 Fuel Assemblies

The reactor shall contain 193 fuel assemblies. Each assembly shall consist of a matrix of Zircalloy or ZIRLO clad fuel rods with an initial composition of natural or slightly enriched uranium dioxide (UO_2) as fuel material. Reload fuel will have a U-235 enrichment of $\leq$ 5.0 weight percent. Limited substitutions of zirconium alloy or stainless steel filler rods for fuel rods, in accordance with approved applications of fuel rod configurations, may be used. Fuel assemblies shall be limited to those fuel designs that have been analyzed with applicable NRC staff approved codes and methods and shown by tests or analyses to comply with all fuel safety design bases. A limited number of lead test assemblies that have not completed representative testing may be placed in nonlimiting core regions.

4.2.2 Control Rod Assemblies

The reactor core shall contain 53 control rod assemblies. The control material shall be silver indium cadmium, as approved by the NRC.

4.0 DESIGN FEATURES

4.3 Fuel Storage

4.3.1 Criticality

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

a. Fuel assemblies having a maximum U-235 enrichment of 5.0 weight percent;

b. $k_{eff} \leq 0.95$ under all possible moderation conditions.

c. A nominal 9.075 inch center to center distance between fuel assemblies placed in the high density fuel storage racks (Region II);

d. A nominal 10.76 inch center to center distance between fuel assemblies placed in low density fuel storage racks (Region I);

4.3.1.2 The new fuel storage racks are designed and shall be maintained with:

a. Fuel assemblies having a maximum U-235 enrichment of 5.0 weight percent;

b. $k_{eff} \leq 0.95$ under all possible moderation conditions (Credit may be taken for burnable integral neutron absorbers);

c. A nominal 20.5 inch center to center distance between fuel assemblies placed in the storage racks.

4.3.2 Drainage

The spent fuel pit is designed and shall be maintained to prevent inadvertent draining of the pool below a nominal elevation of 88 ft.

4.0 DESIGN FEATURES

4.3 Fuel Storage (continued)

4.3.3 Capacity

The spent fuel pit is designed and shall be maintained with a storage capacity limited to no more than 1345 fuel assemblies.

5.0 ADMINISTRATIVE CONTROLS

5.1 Responsibility

5.1.1 The plant manager shall be responsible for overall unit operation and shall delegate in writing the succession to this responsibility during his absence.

The plant manager or his designee shall approve, prior to implementation, each proposed test, experiment or modification to systems or equipment that affect nuclear safety.

5.1.2 The shift supervisor (SS) shall be responsible for the control room command function. During any absence of the SS from the control room while the unit is in MODE 1, 2, 3, or 4, an individual with an active Senior Reactor Operator (SRO) license shall be designated to assume the control room command function. During any absence of the SS from the control room while the unit is in MODE 5 or 6, an individual with an active SRO license or Reactor Operator license shall be designated to assume the control room command function.

5.0 ADMINISTRATIVE CONTROLS

5.2 Organization

5.2.1 Onsite and Offsite Organizations

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

a. Lines of authority, responsibility, and communication shall be defined and established throughout highest management levels, intermediate levels, and all operating organization positions. These relationships shall be documented and updated, as appropriate, in organization charts, functional descriptions of departmental responsibilities and relationships, and job descriptions for key personnel positions, or in equivalent forms of documentation. These requirements, including the plant specific titles of those personnel fulfilling the responsibilities of the positions delineated in these Technical Specifications, shall be documented in the FSAR and Quality Assurance Plan, as appropriate;

b. The plant manager shall be responsible for overall safe operation of the plant and shall have control over those onsite activities necessary for safe operation and maintenance of the plant;

c. The corporate officer with direct responsibility for the plant shall have corporate responsibility for overall plant nuclear safety and shall take any measures needed to ensure acceptable performance of the staff in operating, maintaining, and providing technical support to the plant to ensure nuclear safety; and

d. The individuals who train the operating staff, carry out health physics, or perform quality assurance functions may report to the appropriate onsite manager; however, these individuals shall have sufficient organizational freedom to ensure their independence from operating pressures.

(continued)

5.2 Organization

5.2.2 Unit Staff

The unit staff organization shall include the following:

a. A non-licensed operator shall be assigned to each reactor containing fuel and an additional non-licensed operator shall be assigned for each control room from which a reactor is operating in MODES 1, 2, 3, or 4.

b. At least one licensed Reactor Operator (RO) shall be present 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 Reactor Operator (SRO) shall be present in the control room.

c. Shift crew composition may be less than the minimum requirement of 10 CFR 50.54(m)(2)(i) and 5.2.2.a and 5.2.2.g 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.

d. A radiation protection technician shall be on site when fuel is in the reactor. The position may be vacant for not more than 2 hours, in order to provide for unexpected absence, provided immediate action is taken to fill the required position.

e. Administrative procedures shall be developed and implemented to limit the working hours of unit staff who perform safety related functions (e.g., licensed SROs, licensed ROs, radiation protection technician, auxiliary 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 an 8 or 12 hour day, nominal 40 hour week while the unit 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 modification, on a temporary basis the following guidelines shall be followed:

(continued)

5.2 Organization

5.2.2 Unit Staff (continued)

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, shift turnover can be included in the break;

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 in advance by the plant manager or his designee, in accordance with approved administrative procedures, or by 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 periodically by the plant manager or his designee to ensure that excessive hours have not been assigned. Routine deviation from the above guidelines is not authorized.

f. The operations manager or assistant operations manager shall hold an SRO license.

g. The Shift Technical Advisor (STA) shall provide advisory technical support to the Shift Supervisor (SS) in the areas of thermal hydraulics, reactor engineering, and plant analysis with regard to the safe operation of the unit. In addition, the STA shall meet the qualifications specified by the Commission Policy Statement on Engineering Expertise on Shift. The STA position must be manned in Mode 1, 2, 3 or 4 only.

5.0 ADMINISTRATIVE CONTROLS

5.3 Unit Staff Qualifications

5.3.1 Each member of the unit staff shall meet or exceed the minimum qualifications of ANSI N18.1-1971 for comparable positions, except for the following:

a. The radiation protection manager shall meet or exceed the qualifications of Regulatory Guide 1.8, September 1975; and

b. The operations manager shall meet or exceed the minimum qualifications of ANSI N18.1-1971 except for the SRO license requirement which shall be in accordance with Technical Specification 5.2.2.f.

5.0 ADMINISTRATIVE CONTROLS

5.4 Procedures

5.4.1 Written procedures shall be established, implemented, and maintained covering the following activities:

a. The applicable procedures recommended in Regulatory Guide 1.33, Revision 0, Appendix A, November 1972;

b. The emergency operating procedures required to implement the requirements of NUREG-0737 and to NUREG-0737, Supplement 1, as stated in Generic Letter 82-33;

c. Quality assurance for effluent and environmental monitoring;

d. Fire Protection Program implementation; and

e. All programs specified in Specification 5.5.

5.0 ADMINISTRATIVE CONTROLS

5.5 Programs and Manuals

The following programs shall be established, implemented, and maintained.

5.5.1 Offsite Dose Calculation Manual (ODCM)

a. The ODCM shall contain the methodology and parameters used in the calculation of offsite doses resulting from radioactive gaseous and liquid effluents, in the calculation of gaseous and liquid effluent monitoring alarm and trip setpoints, and in the conduct of the radiological environmental monitoring program; and

b. The ODCM shall also contain the radioactive effluent controls and radiological environmental monitoring activities, and descriptions of the information that should be included in the Annual Radiological Environmental Operating, and Radioactive Effluent Release Reports required by Specification 5.6.2 and Specification 5.6.3.

Licensee initiated changes to the ODCM:

a. Shall be documented and records of reviews performed shall be retained. This documentation shall contain:

   1. Sufficient information to support the change(s) together with the appropriate analyses or evaluations justifying the change(s), and

   2. A determination that the change(s) maintain the levels of radioactive effluent control required by 10 CFR 20.1302, 40 CFR 190, 10 CFR 50.36a, and 10 CFR 50, Appendix I, and not adversely impact the accuracy or reliability of effluent, dose, or setpoint calculations;

b. Shall become effective after the approval of the plant manager; and

c. Shall be submitted to the NRC in the form of a complete, legible copy of the entire ODCM as a part of or concurrent with the Radioactive Effluent Release Report for the period of the report

(continued)

5.5 Programs and Manuals

5.5.1 Offsite Dose Calculation Manual (ODCM) (continued)

in which any change in the ODCM was made. Each change shall be identified by markings in the margin of the affected pages, clearly indicating the area of the page that was changed, and shall indicate the date (i.e., month and year) the change was implemented.

5.5.2 Primary Coolant Sources Outside Containment

This program provides controls to minimize leakage from those portions of systems outside containment that could contain highly radioactive fluids during a serious transient or accident to levels as low as practicable. The system includes the following:

a. Residual Heat Removal System;

b. Cross Connect Between Low Head Recirculation System and High Head Safety Injection System;

c. High Head Safety Injection system (partial);

d. Reactor Coolant Sampling System;

e. Post Accident Containment Air Sampling System;

f. Volume Control Tank (including Reactor Coolant Pump seal return line);

g. Containment Hydrogen Monitoring system.

The program shall include the following:

a. Preventive maintenance and periodic visual inspection requirements; and

b. Integrated leak test requirements for each system at refueling cycle intervals or less.

(continued)

5.5 Programs and Manuals

5.5.3 Post Accident Sampling

This program provides controls that ensure the capability to obtain and analyze reactor coolant, radioactive gases, and particulates in plant gaseous effluents and containment atmosphere samples under accident conditions.

The program shall include the following:

a. Training of personnel;

b. Procedures for sampling and analysis; and

c. Provisions for maintenance of sampling and analysis equipment.

5.5.4 Radioactive Effluent Controls Program

This program conforms to 10 CFR 50.36a for the control of radioactive effluents and for maintaining the doses to members of the public from radioactive effluents as low as reasonably achievable. The program shall be contained in the ODCM, shall be implemented by procedures, and shall include remedial actions tobe taken whenever the program limits are exceeded. The program shall include the following elements:

a. Limitations on the functional capability of radioactive liquid and gaseous monitoring instrumentation including surveillance tests and setpoint determination in accordance with the methodology in the ODCM;

b. Limitations on the concentrations of radioactive material released in liquid effluents to unrestricted areas, conforming to 10 times the concentration values in 10 CFR 20, Appendix B, Table 2, Column 2;

c. Monitoring, sampling, and analysis of radioactive liquid and gaseous effluents in accordance with 10 CFR 20.1302 and with the methodology and parameters in the ODCM;

(continued)

5.5 Programs and Manuals

5.5.4 Radioactive Effluent Controls Program (continued)

d. Limitations on the annual and quarterly doses or dose commitment to a member of the public from radioactive materials in liquid effluents released from each unit to unrestricted areas, conforming to 10 CFR 50, Appendix I;

e. Determination of cumulative and projected dose contributions from radioactive effluents for the current calendar quarter and current calendar year in accordance with the methodology and parameters in the ODCM at least every 31 days;

f. Limitations on the functional capability and use of the liquid and gaseous effluent treatment systems to ensure that appropriate portions of these systems are used to reduce releases of radioactivity when the projected doses in a period of 31 days would exceed 2% of the guidelines for the annual dose or dose commitment, conforming to 10 CFR 50, Appendix I;

g. Limitations on the dose rate resulting from radioactive material released in gaseous effluents to areas beyond the site boundary shall be limited to the following:

   a. For noble gases: Less than or equal to a dose rate of 500 mrems/yr to the total body and less than or equal to a dose rate of 3000 mrems/yr to the skin, and

   b. For iodine-131, tritium, and for all radionuclides in particulate form with half-lives greater than 8 days: Less than or equal to dose rate of 1500 mrems/yr to any organ.

h. Limitations on the annual and quarterly air doses resulting from noble gases released in gaseous effluents from each unit to areas beyond the site boundary, conforming to 10 CFR 50, Appendix I;

(continued)

5.5 Programs and Manuals

5.5.4 Radioactive Effluent Controls Program (continued)

i. Limitations on the annual and quarterly doses to a member of the public from iodine-131, tritium, and all radionuclides in particulate form with half lives > 8 days in gaseous effluents released from each unit to areas beyond the site boundary, conforming to 10 CFR 50, Appendix I; and

j. Limitations on the annual dose or dose commitment to any member of the public due to releases of radioactivity and to radiation from uranium fuel cycle sources, conforming to 40 CFR 190.

5.5.5 Component Cyclic or Transient Limit

This program provides controls to track the FSAR, Section 4.1.5, cyclic and transient occurrences to ensure that components are maintained within the design limits.

5.5.6 Reactor Coolant Pump Flywheel Inspection Program

This program shall provide for the inspection of each reactor coolant pump flywheel. The program shall include inspection frequencies and acceptance criteria. The inspection frequency will ensure that each reactor coolant pump flywheel is surface and volumetrically inspected within 10 years after a flywheel is placed in service following inspection.

(continued)

5.5 Programs and Manuals

5.5.7 Inservice Testing Program

This program provides controls for inservice testing of ASME Code Class 1, 2, and 3 components including applicable supports. The program shall include the following:

a. Testing frequencies specified in Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda as follows:

ASME Boiler and Pressure Vessel Code and applicable Addenda terminology for inservice testing activities	Required Frequencies for performing inservice testing activities
Weekly	At least once per 7 days
Monthly	At least once per 31 days
Quarterly or every 3 months	At least once per 92 days
Semiannually or every 6 months	At least once per 184 days
Every 9 months	At least once per 276 days
Yearly or annually	At least once per 366 days
Biennially or every 2 years	At least once per 731 days

b. The provisions of SR 3.0.2 are applicable to the above required Frequencies for performing inservice testing activities;

c. The provisions of SR 3.0.3 are applicable to inservice testing activities; and

d. Nothing in the ASME Boiler and Pressure Vessel Code shall be construed to supersede the requirements of any TS.

(continued)

5.5 Programs and Manuals

5.5.8 Steam Generator (SG) Tube Surveillance Program

This program provides controls for the inservice inspection of SG tubes to assure the continued integrity of the Reactor Coolant System pressure boundary and shall include the following:

a. SG Selection and SG Tube Sample Size

The minimum sample size shall be in conformance with the requirements specified in Table 5.5-1. Selection and testing of steam generator tubes shall be made on the following basis:

1. At the first inservice inspection subsequent to the pre-service inspection, six percent of the tubes in each of two steam generators shall be inspected as a minimum.

2. At the second inservice inspection subsequent to the pre-service inspection, twelve percent of the tubes in one of the two steam generators not inspected during the first inservice inspection shall be inspected as a minimum.

3. At the third inservice inspection subsequent to the pre-service inspection, twelve percent of the tubes in the steam generator not inspected during the first two inservice inspections shall be inspected as a minimum.

4. Fourth and subsequent inservice inspections may be limited to one steam generator on a rotating schedule encompassing 12% of the tubes if the results of the first or previous inspections indicate that all steam generators are performing in like manner. Under some circumstances, the operating conditions in one or more steam generators may be found to be more severe than those in other steam generators. Under such circumstances, the sample sequences should be modified to inspect the steam generator with the most severe conditions.

5. Unscheduled inspections should be conducted on the affected steam generator(s) in accordance with the first sample

(continued)

5.5 Programs and Manuals

5.5.8 Steam Generator (SG) Tube Surveillance Program (continued)

inspection specified in Table 5.5-1 in the event of primary-to-secondary tube leaks (not including leaks originated from tube-to-tube sheet welds) exceeding technical specifications, a seismic occurrence greater than an operating basis earthquake, a loss-of-coolant accident requiring actuation of engineered safeguards, or a major steam line or feedwater line break.

b. SG Tube Selection Criteria

1. Tubes for the inspection should be selected on a random basis except where experience in similar plants with similar water chemistry indicates critical areas to be inspected.

2. The first sample inspection subsequent to the pre-service inspection should include all non-plugged tubes that previously had detectable wall penetration (> 20%) and should also include tubes in those areas where experience has indicated potential problems.

3. The second and third sample inspections in Table 5.5-1 may be limited to the partial tube inspection only, concentrating on tubes in the areas of the tube sheet array and on the portion of the tube where tubes with imperfections were found.

4. In all inspections, previously degraded tubes must exhibit significant (>10%) further wall penetration to be included in the percentage calculation for the result categories in Table 5.5-1.

c. Inspection FREQUENCY

1. Inservice inspections should be not less than 12 or more than 24 calendar months after the previous inspection.

(continued)

5.5 Programs and Manuals

5.5.8 Steam Generator (SG) Tube Surveillance Program (continued)

2. If the results of two consecutive inspections, not including the preservice inspection, all fall into the C-1 category, the frequency of inspection may be extended to 40-month intervals. Also, if it can be demonstrated through two consecutive inspections that previously observed degradation has not continued and no additional degradation has occurred, a 40-month inspection interval may be initiated.

3. SR 3.0.2 is applicable to the Steam Generator Tube Surveillance Program test frequencies.

d. Classification of Test Results

1. Definitions:

Imperfection is an exception to the dimension, finish, or contour required by drawing or specification.

Degradation means a service-induced cracking, wastage, wear or corrosion.

Degraded Tube is a tube that contains imperfections caused by degradation large enough to be reliably detected by eddy current inspection. This is considered to be 20% degradation.

% Degradation is an estimate % of the tube wall thickness affected or removed by degradation.

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

(continued)

5.5 Programs and Manuals

5.5.8 Steam Generator (SG) Tube Surveillance Program (continued)

Tube Plugging Limit is the tube imperfection depth at or beyond which the tube must either be removed from service or repaired. This is considered to be an imperfection depth of 40%.

Sleeve Plugging Limit is the sleeve imperfection depth at or beyond which the sleeved tube must be removed from service or repaired. This is considered to be an imperfection depth of 40% for tube sleeves.

Tube Inspection is a full length inspection for the initial 3% sample specified in Table 5.5-1. Supplemental sample inspections (after the initial 3% sample) may be limited to a partial length inspection concentrating on those locations where degradation has been found.

2. Results Classifications

The results of each sampling examination of a steam generator shall be classified into the following three categories:

Category C-1: Less than 5% of the total tubes inspected are degraded tubes and none are defective.

Category C-2: One or more but not more than 1% of the total tubes inspected are defective or between 5 and 10% of the tubes inspected are degraded tubes.

Category C-3: More than 10% of the total tubes inspected are degraded or more than 1% of the tubes inspected are defective.

e. Corrective Action

1. The inspection result classification and the corresponding required action are specified in Table 5.5-1.

(continued)

5.5 Programs and Manuals

5.5.8 Steam Generator (SG) Tube Surveillance Program (continued)

2. All leaking tubes and defective tubes should be plugged or repaired.

3. Results of steam generator tube inspections which fall into Category C-3 of Table 5.5-1 require notification of the NRC within 15 days of this determination.

4. NRC approval prior to startup is required when SG Tube Inspections identify Category C-3 degradation or defects in more than one SG.

(continued)

5.5 Programs and Manuals

TABLE 5.5-1 (page 1 of 2)
STEAM GENERATOR TUBE INSPECTION

First Sample		Second Sample		Third Sample	
Result	Required Action	Result	Required Action	Result	Required Action
C-1	Acceptable for Service	C-1	Acceptable for Service	C-1	Acceptable for Service
C-2	Plug or Repair defective tubes AND Inspect additional 2S tubes in this SG	C-1	Acceptable for Service	N/A	N/A
		C-2	Plug or Repair defective tubes AND Inspect additional 4S tubes in this SG	C-1	Acceptable for Service
				C-2	Plug or Repair defective tubes AND Acceptable for Service
				C-3	Inspect all tubes in this SG AND Plug or Repair defective tubes AND Inspect 2S tubes in each other SG
		C-3	Inspect all tubes in this SG AND Plug or Repair defective tubes AND Inspect 2S tubes in each other SG	N/A	N/A

(continued)

5.5 Programs and Manuals

TABLE 5.5-1 (page 2 of 2)
STEAM GENERATOR TUBE INSPECTION

First Sample		Second Sample		Third Sample	
Result	Required Action	Result	Required Action	Result	Required Action
C-3	Inspect all tubes in this SG AND Plug or Repair defective tubes AND Inspect 2S tubes in each other SG	All other SGs C-1	Acceptable for Service	N/A	
		Some SGs C-2 AND No other SG C-3	Plug or Repair defective tubes AND Inspect additional 4S tubes in this SG		
		Other SG C-3	Inspect all tubes in all SGs. AND Plug or Repair defective tubes AND Report and NRC Approval required prior to startup		

Sample Size shall consist of a minimum of S tubes per Steam Generator (SG)

$S=3(N/n)\%$

where:

N is the number of steam generators in the plant

n is the number of steam generators inspected during an examination

Result Classifications (C-1, C-2 and C-3) are defined in Section 5.5.8.d.

(continued)

5.5 Programs and Manuals

5.5.9 Secondary Water Chemistry Program

This program provides controls for monitoring secondary water chemistry to inhibit SG tube degradation. The program shall include:

a. Identification of a sampling schedule for the critical variables and control points for these variables;

b. Identification of the procedures used to measure the values of the critical variables;

c. Identification of process sampling points, which shall include monitoring the condenser hot wells for evidence of condenser in leakage;

d. Procedures for the recording and management of data;

e. Procedures defining corrective actions for all off control point chemistry conditions; and

f. A procedure identifying the authority responsible for the interpretation of the data and the sequence and timing of administrative events, which is required to initiate corrective action.

(continued)

5.5 Programs and Manuals

5.5.10 Ventilation Filter Testing Program (VFTP)

This program provides controls for implementation of required testing the ventilation filter function for the Fuel Storage Building Emergency Ventilation System, Control Room Ventilation System, Containment Fan Cooler Units, and Containment Purge System.

Applicable tests described in Specifications 5.5.10.a, 5.5.10.b, 5.5.10.c and 5.5.10.d shall be performed:

1) After 720 hours of charcoal adsorber use since the last test; and,

2) After 24 months of standby service for the Fuel Storage Building Emergency Ventilation System, Control Room Ventilation System, and Containment Fan Cooler Units; and,

3) After 18 months of standby service for the Containment Purge System; and,

4) After each complete or partial replacement of the HEPA filter train or charcoal adsorber filter; and,

5) After any structural maintenance on the system housing that could alter system integrity; and,

6) After significant painting, fire, or chemical release in any ventilation zone communicating with the system while it is in operation.

SR 3.0.2 is applicable to the Ventilation Filter Testing Program.

(continued)

5.5 Programs and Manuals

5.5.10 Ventilation Filter Testing Program (VFTP) (continued)

a. Demonstrate for each system that an inplace test of the high efficiency particulate air (HEPA) filters shows the specified penetration and system bypass leakage when tested in accordance with the referenced standard at the flowrate specified below.

Ventilation System	Removal Efficiency	Flowrate (cfm)	Reference Standard
Fuel Storage Building Emergency Ventilation System	≥ 99%	80% to 120% of design accident rate	Regulatory Guide 1.52, Rev 2, Sections C.5.a and C.5.c
Control Room Ventilation System	≥ 99%	80% to 120% of design accident rate	Regulatory Guide 1.52, Rev 2, Sections C.5.a and C.5.c
Containment Fan Cooler Units	≥ 99%	80% to 120% of design accident rate	Regulatory Guide 1.52, Rev 2, Sections C.5.a and C.5.c
Containment Purge System	≥ 99%	90% to 110% of design operating rate	Regulatory Guide 1.52, Rev 2, Sections C.5.a and C.5.c

(continued)

5.5 Programs and Manuals

5.5.10 Ventilation Filter Testing Program (VFTP) (continued)

b. Demonstrate for each system that an inplace test of the charcoal adsorber shows the specified penetration and system bypass leakage when tested in accordance with the referenced standard at the flowrate specified below.

Ventilation System	Removal Efficiency	Flowrate (cfm)	Reference Standard
Fuel Storage Building Emergency Ventilation System	≥ 99%	80% to 120% of design accident rate	Regulatory Guide 1.52, Rev 2, Sections C.5.a and C.5.d
Control Room Ventilation System	≥ 99%	80% to 120% of design accident rate	Regulatory Guide 1.52, Rev 2, Sections C.5.a and C.5.d
Containment Fan Cooler Units	≥ 99%	80% to 120% of design accident rate	Regulatory Guide 1.52, Rev 2, Sections C.5.a and C.5.d
Containment Purge System	≥ 99%	90% to 110% of design operating rate	Regulatory Guide 1.52, Rev 2, Sections C.5.a and C.5.d

(continued)

5.5 Programs and Manuals

5.5.10 Ventilation Filter Testing Program (VFTP) (continued)

c. Demonstrate for each system that a laboratory test of a sample of the charcoal adsorber shows the methyl iodide removal efficiency specified below when tested at the conditions specified below.

Ventilation System	Methyl iodide removal efficiency (%):	Methyl iodide inlet concentration (mg/m³):	Flow velocity equivalent to following flow rate (cfm):	Temperature (degrees F):	Relative Humidity (%):
Fuel Storage Building Emergency Ventilation System	≥ 90	0.05 to 0.15	80% to 120% of design accident rate	≥ 125	≥ 95
Control Room Ventilation System	≥ 90	0.05 to 0.15	80% to 120% of design accident rate	≥ 125	≥ 95
Containment Fan Cooler Units	≥ 85	5 to 15	80% to 120% of design accident rate	≥ 250	≥ 95
Containment Purge System	≥ 90	*	80% to 120% of design operating rate	*	*

* Per test 5.b in Table 2 of Regulatory Guide 1.52, March 19978.

(continued)

5.5 Programs and Manuals

5.5.10 Ventilation Filter Testing Program (VFTP) (continued)

d. Demonstrate for each system that the pressure drop across the combined HEPA filters, the demisters and prefilters (if installed), and the charcoal adsorbers is less than the value specified below when tested at the flowrate specified below.

Ventilation System	Delta P (inches wg)	Flowrate (cfm):
Fuel Storage Building Emergency Ventilation System	6	≥ 90% of design accident rate
Control Room Ventilation System	6	≥ 90% of design accident rate
Containment Fan Cooler Units	6	≥ 90% of design accident rate

(continued)

5.5 Programs and Manuals

5.5.11 Explosive Gas and Storage Tank Radioactivity Monitoring Program

This program provides controls for potentially explosive gas mixtures contained in the Waste Gas Holdup System, the quantity of radioactivity contained in gas storage tanks, and the quantity of radioactivity contained in unprotected outdoor liquid storage tanks. The quantities of radioactivity in gas and liquid radwaste storage tanks shall be determined in accordance with methodology and parameters specified in the ODCM.

The program shall include:

a. The limits for concentrations of hydrogen and oxygen in the Waste Gas Holdup System and a surveillance program to ensure the limits are maintained. Such limits shall be appropriate to the system's design criteria (i.e., whether or not the system is designed to withstand a hydrogen explosion);

b. A surveillance program to ensure that the quantity of radioactivity contained in each gas storage tank shall be limited to less than or equal to 50,000 curies noble gases (considered as DOSE EQUIVALENT Xe-133); and

c. A surveillance program to ensure that the quantity of radioactivity contained in all outdoor liquid radwaste tanks that are not surrounded by liners, dikes, or walls, capable of holding the tanks' contents and that do not have tank overflows and surrounding area drains connected to the Liquid Radwaste Treatment System is less than or equal to 10 curies, excluding tritium and dissolved or entrained noble gases.

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the Explosive Gas and Storage Tank Radioactivity Monitoring Program surveillance frequencies.

(continued)

5.5 Programs and Manuals

5.5.12 Diesel Fuel Oil Testing Program

A diesel fuel oil testing program to implement required testing of both new fuel oil and stored fuel oil shall be established. The program shall include sampling requirements, testing requirements, and acceptance criteria, all in accordance with applicable ASTM Standards.

Program requirements for the DG fuel oil storage tanks will ensure the following:

a. Acceptability of new fuel oil for use prior to addition to storage tanks by determining that the fuel oil has:

   1. an API gravity or an absolute specific gravity within limits,

   2. a flash point and kinematic viscosity within limits for ASTM 2D fuel oil, and

   3. a clear and bright appearance with proper color.

b. Within 31 days following addition of new fuel oil to storage tanks, verify that the properties of the new fuel oil, other than those addressed in 5.5.12.a, are within limits for applicable ASTM standards; and

c. Every 31 days, verify total particulate concentration of the fuel oil is ≤ 10 mg/l when tested in accordance with applicable ASTM standards.

Program requirements for the reserve storage tanks will ensure the following:

a. Fuel oil is commercial grade and compatible for use with the IP3 diesels.

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the Diesel fuel Oil Testing Program testing frequencies.

(continued)

5.5 Programs and Manuals

5.5.13 Technical Specifications (TS) Bases Control Program

This program provides a means for processing changes to the Bases of these Technical Specifications.

a. Changes to the Bases of the TS shall be made under appropriate administrative controls and reviews.

b. Licensees may make changes to Bases without prior NRC approval provided the changes do not involve either of the following:

   1. a change in the TS incorporated in the license; or

   2. a change to the updated FSAR or Bases that involves an unreviewed safety question as defined in 10 CFR 50.59.

c. The Bases Control Program shall contain provisions to ensure that the Bases are maintained consistent with the FSAR.

d. Proposed changes that do not meet the criteria of Specification 5.5.13.b above shall be reviewed and approved by the NRC prior to implementation. Changes to the Bases implemented without prior NRC approval shall be provided to the NRC on a frequency consistent with 10 CFR 50.71(e).

5.5.14 Safety Function Determination Program (SFDP)

This program ensures loss of safety function is detected and appropriate actions taken. Upon entry into LCO 3.0.6, an evaluation shall be made to determine if loss of safety function exists. Additionally, other appropriate actions may be taken as a result of the support system inoperability and corresponding exception to entering supported system Condition and Required Actions. This program implements the requirements of LCO 3.0.6. The SFDP shall contain the following:

a. Provisions for cross train checks to ensure a loss of the capability to perform the safety function assumed in the accident analysis does not go undetected;

(continued)

5.5 Programs and Manuals

5.5.14 Safety Function Determination Program (SFDP) (continued)

b. Provisions for ensuring the plant is maintained in a safe condition if a loss of function condition exists;

c. Provisions to ensure that an inoperable supported system's Completion Time is not inappropriately extended as a result of multiple support system inoperabilities; and

d. Other appropriate limitations and remedial or compensatory actions.

A loss of safety function exists when, assuming no concurrent single failure, a safety function assumed in the accident analysis cannot be performed. For the purpose of this program, a loss of safety function may exist when a support system is inoperable, and:

a. A required system redundant to the system(s) supported by the inoperable support system is also inoperable; or

b. A required system redundant to the system(s) in turn supported by the inoperable supported system is also inoperable; or

c. A required system redundant to the support system(s) for the supported systems (a) and (b) above is also inoperable.

The SFDP identifies where a loss of safety function exists. If a loss of safety function is determined to exist by this program, the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists are required to be entered.

(continued)

5.5 Programs and Manuals

5.5.15 Containment Leakage Rate Testing Program

A program shall be established to implement the leakage rate testing of the containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B, as modified by approved exemptions. This program shall be in accordance with the guidelines contained in Regulatory Guide 1.163, "Performance-Based Containment Leak Test Program, dated September 1995" as modified by the following exception:

> ANS 56.8-1994, Section 3.3.1: WCCPPS isolation valves are not Type C tested.

The maximum allowable primary containment leakage rate, L_a, at a minimum test pressure equal to P_a, shall be 0.1% of primary containment air weight per day. P_a is the peak calculated containment internal pressure related to the design basis accident.

Leakage acceptance criteria are:

a. Containment leakage rate acceptance criterion is $\leq 1.0\ L_a$. During the first unit startup following testing in accordance with this program, the leakage rate acceptance criteria are $\leq 0.60\ L_a$ for the Type B and C tests and $\leq 0.75\ L_a$ for Type A tests;

b. Air lock testing acceptance criteria are:

   1) Overall air lock leakage rate is $\leq 0.05\ L_a$ when tested at $\geq P_a$,

   2) For each door, leakage rate is $\leq 0.01\ L_a$ when pressurized to $\geq P_a$,

c. Isolation Valve Seal Water System leakage rate acceptance criterion is 14,700 cc/hr at 1.1 P_a.

SR 3.0.2 is not applicable to the Containment Leakage Rate Testing Program because testing Frequencies are established by 10 CFR 50, Appenddix J.

SR 3.0.3 is applicable to the Containment Leakage Rate Testing Program.

5.0 ADMINISTRATIVE CONTROLS

5.6 Reporting Requirements

The following reports shall be submitted in accordance with 10 CFR 50.4.

5.6.1 Occupational Radiation Exposure Report

A tabulation on an annual basis of the number of station, utility, and other personnel (including contractors), for whom monitoring was performed, receiving an annual deep dose equivalent ≥ 100 mrems and the associated collective deep dose equivalent (reported in person - rem) according to work and job functions (e.g., reactor operations and surveillance, inservice inspection, routine maintenance, special maintenance, waste processing, and refueling). This tabulation supplements the requirements of 10 CFR 20.2206. The dose assignments to various duty functions may be estimated based on pocket ionization chamber, thermoluminescence dosimeter (TLD), electronic dosimeter, or film badge measurements. Small exposures totaling < 20 percent of the individual total dose need not be accounted for. In the aggregate, at least 80 percent of the total deep dose equivalent received from external sources should be assigned to specific major work functions. The report covering the previous calendar year shall be submitted by April 30 of each year.

5.6.2 Annual Radiological Environmental Operating Report

-------------------------------NOTE-------------------------------
A single submittal may be made for a multiple unit station. The submittal should combine sections common to all units at the station.

The Annual Radiological Environmental Operating Report covering the operation of the unit during the previous calendar year shall be submitted by May 15 of each year. The report shall include summaries, interpretations, and analyses of trends of the results of the radiological environmental monitoring program for the reporting period. The material provided shall be consistent with the objectives outlined in the Offsite Dose Calculation Manual (ODCM), and in 10 CFR 50, Appendix I, Sections IV.B.2, IV.B.3, and IV.C.

(continued)

5.6 Reporting Requirements

5.6.2 Annual Radiological Environmental Operating Report (continued)

A full listing of the information to be contained in the Annual Radioactive Effluent Release Report is provided in the ODCM.

5.6.3 Radioactive Effluent Release Report

--------------------------------NOTE--------------------------------
A single submittal may be made for a multiple unit station. The submittal shall combine sections 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.

The Radioactive Effluent Release Report covering the operation of the unit in the previous year shall be submitted prior to May 1 of each year in accordance with 10 CFR 50.36a. The report shall include a summary of the quantities of radioactive liquid and gaseous effluents and solid waste released from the unit. The material provided shall be consistent with the objectives outlined in the ODCM and Process Control Program and in conformance with 10 CFR Part 50.36a and 10 CFR 50, Appendix I, Section IV.B.1.

5.6.4 Monthly Operating Reports

Routine reports of operating statistics and shutdown experience, including documentation of all challenges to the pressurizer power operated relief valves or pressurizer safety valves, shall be submitted on a monthly basis no later than the 15th of each month following the calendar month covered by the report.

5.6.5 CORE OPERATING LIMITS REPORT (COLR)

a. Core operating limits shall be established prior to each reload cycle, or prior to any remaining portion of a reload cycle, and shall be documented in the COLR for the following:

(continued)

5.6 Reporting Requirements (continued)

5.6.5 CORE OPERATING LIMITS REPORT (COLR) (continued)

1. Specification 3.2.3, AXIAL FLUX DIFFERENCE (AFD);

2. Specification 3.2.1, Heat Flux Hot Channel Factor (FQ(Z));

3. Specification 3.2.2, Nuclear Enthalpy Rise Hot Channel Factor;

4. Specification 3.1.5, Shutdown Bank Insertion Limits; and

5. Specification 3.1.6, Control Bank Insertion Limits.

b. The analytical methods used to determine the core operating limits shall be those previously reviewed and approved by the NRC, specifically those described in the following documents:

1. WCAP-9272-P-A, "WESTINGHOUSE RELOAD SAFETY EVALUATION METHODOLOGY," July 1985 (W Proprietary). (Specifications 3.1.5, Shutdown Bank Insertion Limits, 3.1.6, Control Bank Insertion Limits, and 3.2.2, Nuclear Enthalpy Rise Hot Channel Factor);

2a. WCAP-8385, "POWER DISTRIBUTION CONTROL AND LOAD FOLLOWING PROCEDURES, TOPICAL REPORT," September 1974 (W Proprietary). (Specification 3.2.3, Axial Flux Difference (AFD) (Constant Axial Offset Control);

2b. T. M. Anderson to K. Kneil (Chief of Core Performance Branch, NRC) January 31, 1980 -- Attachment: Operation and Safety Analysis Aspects of an Improved Load Follow Package. (Specification 3.2.3, Axial Flux Difference (AFD) (Constant Axial Offset Control));

2c. NUREG-0800, Standard Review Plan, U.S. Nuclear Regulatory Commission, Section 4.3, Nuclear Design, July 1981. Branch Position CPB 4.3-1, Westinghouse Constant Axial Offset Control (CAOC), Rev. 2, July 1981. (Specification 3.2.3, Axial Flux Difference (AFD) (Constant Axial Offset Control));

(continued)

5.6 Reporting Requirements (continued)

5.6.5 CORE OPERATING LIMITS REPORT (COLR) (continued)

3a. WCAP-9220-P-A, Rev. 1, "WESTINGHOUSE ECCS EVALUATION MODEL-1981 VERSION," February 1982 (W Proprietary). (Specification 3.2.1, Heat Flux Hot Channel Factor (FQ(Z)));

3b. WCAP-9561-P-A ADD. 3, Rev. 1, "BART A-1: A COMPUTER CODE FOR THE BEST ESTIMATE ANALYSIS OF REFLOOD TRANSIENTS, SPECIAL REPORT: THIMBLE MODELING W ECCS EVALUATION MODEL," July 1986 (W Proprietary). (Specification 3.2.1, Heat Flux Hot Channel Factor (FQ(Z)));

3c. WCAP-10266-P-A Rev. 2, "THE 1981 VERSION OF WESTINGHOUSE EVALUATION MODEL USING BASH CODE," March 1987, (W Proprietary).(Specification 3.2.1, Heat Flux Hot Channel Factor (FQ(Z)));

3d. WCAP-10054-P-A, "SMALL BREAK ECCS EVALUATION MODEL USING NOTRUMP CODE," (W Proprietary). (Specification 3.2.1, Heat Flux Hot Channel Factor (FQ(Z));

3e. WCAP-10079-P-A, "NOTRUMP NODAL TRANSIENT SMALL BREAK AND GENERAL NETWORK CODE," (W Proprietary). (Specification 3.2.1, Heat Flux Hot Channel Factor (FQ(Z))); and

3f. WCAP-12610, "VANTAGE+ Fuel Assembly Report," (W Proprietary). (Specification 3.2.1, Heat Flux Hot Channel Factor).

c. The core operating limits shall be determined such that all applicable limits (e.g., fuel thermal mechanical limits, core thermal hydraulic limits, Emergency Core Cooling Systems (ECCS) limits, nuclear limits such as SDM, transient analysis limits, and accident analysis limits) of the safety analysis are met.

d. The COLR, including any midcycle revisions or supplements, shall be provided for each reload cycle to the NRC.

(continued)

5.6 Reporting Requirements (continued)

5.6.6 Reactor Coolant System (RCS) PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR)

a. RCS pressure and temperature limits for heat up, cooldown, low temperature operation, criticality, and hydrostatic testing as well as heatup and cooldown rates shall be established and documented in the PTLR for the following:

1. Specification 3.4.3 RCS Pressure and Temperature (P/T) Limits; and

2. Specification 3.4.12, Low Temperature Overpressure Protection (LTOP):

b. The analytical methods used to determine the RCS pressure and temperature limits shall be those previously reviewed and approved by the NRC, specifically those described in the following documents:

Reg. Guide 1.99, Radiation Embrittlement of Reactor Vessel Materials, Rev 2, and Safety Evaluation by the Office for Nuclear Reactor Regulation Related to Amendment 109 to Facility Operating License No. DPR-64, Indian Point Nuclear Generating Station No. 3.

c. The PTLR shall be provided to the NRC for each reactor vessel fluence period and for any revision or supplement thereto.

5.6.7 Post Accident Monitoring Instrumentation (PAM) Report

When a report is required by LCO 3.3.3, "Post Accident Monitoring (PAM) Instrumentation," a report shall be submitted within the 14 days. The report shall outline the preplanned alternate method of monitoring, the cause of the inoperability, and the plans and schedule for restoring the instrumentation channels of the Function to OPERABLE status.

5.6 Reporting Requirements (continued)

5.6.8 Steam Generator Tube Inspection Report

The number of tubes plugged or repaired in each steam generator during each inservice inspection of steam generator tube shall be reported to the Commission within 15 days following the inspection.

Complete results of the steam generator tube inservice inspections shall be reported in writing on an annual basis for the period in which the inspection was completed per Specification 5.5.8. This report shall include:

a. Number and extent of tubes inspected.

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

c. Identification of the tubes plugged and the tubes repaired.

5.0 ADMINISTRATIVE CONTROLS

5.7 High Radiation Area

5.7.1 Pursuant to 10 CFR 20, paragraph 20.1601(c), in lieu of the requirements of 10 CFR 20.1601, each high radiation area, as defined in 10 CFR 20, in which the intensity of radiation is > 100 mrem/hr but < 1000 mrem/hr, 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., radiation protection technicians) 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 < 1000 mrem/hr, 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:

a. A radiation monitoring device that continuously indicates the radiation dose rate in the area.

b. A radiation monitoring device that 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 are aware of them.

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 radiation protection manager in the RWP.

5.7.2 In addition to the requirements of Specification 5.7.1, areas with radiation levels ≥ 1000 mrem/hr shall be provided with locked or continuously guarded doors to prevent unauthorized entry and the keys shall be maintained under the administrative control of the shift supervisor on duty or health physics supervision.

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B 2.0 SAFETY LIMITS (SLs)

B 2.1.1 Reactor Core SLs

BASES

BACKGROUND

GDC 10 (Ref. 1) requires that specified acceptable fuel design limits are not exceeded during steady state operation, normal operational transients, and anticipated operational occurrences (AOOs). This is accomplished by having a departure from nucleate boiling (DNB) design basis, which corresponds to a 95% probability at a 95% confidence level (the 95/95 DNB criterion) that DNB will not occur and by requiring that fuel centerline temperature stays below the melting temperature.

The restrictions of this SL prevent overheating of the fuel and cladding, as well as possible cladding perforation, that would result in the release of fission products to the reactor coolant. Overheating of the fuel is prevented by maintaining the steady state peak linear heat rate (LHR) below the level at which fuel centerline melting occurs. Overheating of the fuel cladding is prevented by restricting fuel operation to within the nucleate boiling regime, where the heat transfer coefficient is large and the cladding surface temperature is slightly above the coolant saturation temperature.

Fuel centerline melting occurs when the local LHR, or power peaking, in a region of the fuel is high enough to cause the fuel centerline temperature to reach the melting point of the fuel. Expansion of the pellet upon centerline melting may cause the pellet to stress the cladding to the point of failure, allowing an uncontrolled release of activity to the reactor coolant.

Operation above the boundary of the nucleate boiling regime could result in excessive cladding temperature because of the onset of DNB and the resultant sharp reduction in heat transfer coefficient. Inside the steam film, high cladding temperatures are reached, and a cladding water (zirconium water) reaction may take place. This chemical reaction results in oxidation of the fuel cladding to a structurally weaker form. This weaker form may lose its integrity, resulting in an uncontrolled release of activity to the reactor coolant.

BASES

BACKGROUND (Continued)

The proper functioning of the Reactor Protection System (RPS) and steam generator safety valves prevents violation of the reactor core SLs.

APPLICABLE SAFETY ANALYSES

The fuel cladding must not sustain damage as a result of normal operation and AOOs. The reactor core SLs are established to preclude violation of the following fuel design criteria:

a. There must be at least 95% probability at a 95% confidence level (the 95/95 DNB criterion) that the hot fuel rod in the core does not experience DNB; and

b. The hot fuel pellet in the core must not experience centerline fuel melting.

The Reactor Protection System (Ref. 2), in combination with all the LCOs, are designed to prevent any anticipated combination of transient conditions for Reactor Coolant System (RCS) temperature, pressure, and THERMAL POWER level that would result in a departure from nucleate boiling ratio (DNBR) of less than the DNBR limit and preclude the existence of flow instabilities.

Automatic enforcement of these reactor core SLs is provided by the following functions:

a. High pressurizer pressure trip;

b. Low pressurizer pressure trip;

c. Overtemperature ΔT trip;

d. Overpower ΔT trip;

e. Power Range Neutron Flux trip; and

BASES

APPLICABLE SAFETY ANALYSES (continued)

f. Steam generator safety valves.

The limitation that the average enthalpy in the hot leg be less than or equal to the enthalpy of saturated liquid also ensures that the ΔT measured by instrumentation, used in the RPS design as a measure of core power, is proportional to core power.

The SLs represent a design requirement for establishing the RPS trip setpoints identified previously. LCO 3.4.1, "RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits," or the assumed initial conditions of the safety analyses (as indicated in the FSAR, Ref. 2) provide more restrictive limits to ensure that the SLs are not exceeded.

SAFETY LIMITS

The curves provided in Figure 2.1-1 show the loci of points of thermal power, Reactor Coolant System pressure and vessel inlet temperature for which the calculated DNBR is no less than the Safety Limit DNBR value or the average enthalpy at the vessel exit is less than the enthalpy of saturated liquid.

The calculation of these limits assumes:

1. $F_{\Delta H}^{RTP} = F_{\Delta H}^{N}$ limit at RTP specified in the COLR;
2. An equivalent steam generator tube plugging level of up to 30% in any steam generator provided the equivalent average plugging level in all steam generators is less than or equal to 24% (Ref. 3);
3. Reactor coolant system total flow rate of greater than or equal to 375,600 gpm as measured at the plant; and,
4. A reference cosine with a peak of 1.55 for axial power shape.

BASES

SAFETY LIMITS (continued)

Figure 2.1-1 includes an allowance for an increase in the enthalpy rise hot channel factor at reduced power based on the expression:

$$F_{\Delta H}^{N} \le F_{\Delta H}^{RTP}(1 + PF_{\Delta H}(1-P))$$

Where
P is the fraction of Rated Thermal Power;
$F_{\Delta H}^{RTP}$ is the $F_{\Delta H}^{N}$ limit at RTP specified in the COLR; and,
$PF_{\Delta H}$ is the Power Factor Multiplier specified in the COLR.

When flow or $F_{\Delta H}$ is measured, no additional allowances are necessary prior to comparison with the limits presented. A 2.9% measurement uncertainty on Flow and a 4% measurement uncertainty of $F_{\Delta H}$ have already been included in the above limits.

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

APPLICABILITY

SL 2.1.1 only applies in MODES 1 and 2 because these are the only MODES in which the reactor is critical. Automatic protection functions are required to be OPERABLE during MODES 1 and 2 to ensure operation within the reactor core SLs. The steam generator safety valves or automatic protection actions serve to prevent RCS heatup to the reactor core SL conditions or to initiate a reactor trip function, which forces the unit into MODE 3. Setpoints for the reactor trip functions are specified in LCO 3.3.1, "Reactor Protection System (RPS) Instrumentation." In MODES 3, 4, 5, and 6, Applicability is not required since the reactor is not generating significant THERMAL POWER.

BASES

SAFETY LIMIT VIOLATIONS

If SL 2.1.1 is violated, the requirement to go to MODE 3 places the unit in a MODE in which this SL is not applicable. The allowed Completion Time of 1 hour recognizes the importance of bringing the unit to a MODE of operation where this SL is not applicable, and reduces the probability of fuel damage.

REFERENCES

1. 10 CFR 50, Appendix A.

2. FSAR, Section 7.2.

3. WCAP-10705, Safety Evaluation for Indian Point Unit 3 with Asymmetric Tube Plugging Among Steam Generators, October 1984.

B 2.0 SAFETY LIMITS (SLs)

B 2.1.2 Reactor Coolant System (RCS) Pressure SL

BASES

BACKGROUND

The SL on RCS pressure protects the integrity of the RCS against overpressurization. In the event of fuel cladding failure, fission products are released into the reactor coolant. The RCS then serves as the primary barrier in preventing the release of fission products into the atmosphere. By establishing an upper limit on RCS pressure, the continued integrity of the RCS is ensured. According to 10 CFR 50, Appendix A, GDC 14, "Reactor Coolant Pressure Boundary," and GDC 15, "Reactor Coolant System Design" (Ref. 1), the reactor coolant pressure boundary (RCPB) design conditions are not to be exceeded during normal operation and anticipated operational occurrences (AOOs). Also, in accordance with GDC 28, "Reactivity Limits" (Ref. 1), reactivity accidents, including rod ejection, do not result in damage to the RCPB greater than limited local yielding.

The design pressure of the RCS is 2485 psig. During normal operation and AOOs, RCS pressure is limited from exceeding the design pressure by more than 10%, in accordance with Section III of the ASME Code (Ref. 2). To ensure system integrity, all RCS components are hydrostatically tested at 125% of design pressure, according to the ASME Code requirements prior to initial operation when there is no fuel in the core. Following inception of unit operation, RCS components shall be pressure tested, in accordance with the requirements of ASME Code, Section XI (Ref. 3).

Overpressurization of the RCS could result in a breach of the RCPB. If such a breach occurs in conjunction with a fuel cladding failure, fission products could enter the containment atmosphere, raising concerns relative to limits on radioactive releases specified in 10 CFR 100, "Reactor Site Criteria" (Ref. 4).

BASES

APPLICABLE SAFETY ANALYSES

The RCS pressurizer safety valves, the main steam safety valves (MSSVs), and the reactor high pressure trip have settings established to ensure that the RCS pressure SL will not be exceeded.

The RCS pressurizer safety valves are sized to prevent system pressure from exceeding the design pressure by more than 10%, as specified in Section III of the ASME Code for Nuclear Power Plant Components (Ref. 2). The transient that establishes the required relief capacity, and hence valve size requirements and lift settings, is a complete loss of external load without a direct reactor trip. During the transient, no control actions are assumed, except that the safety valves on the secondary plant are assumed to open when the steam pressure reaches the secondary plant safety valve settings, and nominal feedwater supply is maintained.

The Reactor Protection System setpoints (Ref. 5), together with the settings of the MSSVs, provide pressure protection for normal operation and AOOs. The reactor high pressure trip setpoint is specifically set to provide protection against overpressurization (Ref. 5). The safety analyses for both the high pressure trip and the RCS pressurizer safety valves are performed using conservative assumptions relative to pressure control devices.

More specifically, no credit is taken for operation of the following:

a. Pressurizer Power Operated Relief Valves (PORVs);

b. Atmospheric Dump Valves;

c. Steam Dump System;

d. Reactor Control System;

e. Pressurizer Level Control System; or

f. Pressurizer Spray.

BASES

SAFETY LIMITS

The maximum transient pressure allowed in the RCS pressure vessel under the ASME Code, Section III, is 110% of design pressure. The maximum transient pressure allowed in the RCS piping, valves, and fittings under USAS, Section B31.1 (Ref. 6) is 120% of design pressure. The most limiting of these two allowances is the 110% of design pressure; therefore, the SL on maximum allowable RCS pressure is 2735 psig.

APPLICABILITY

SL 2.1.2 applies in MODES 1, 2, 3, 4, and 5 and in MODE 6 when the reactor vessel head is on because this SL could be approached or exceeded in these MODES due to overpressurization events. The SL is not applicable in MODE 6 when reactor vessel head is removed because the RCS can not be pressurized.

SAFETY LIMIT VIOLATIONS

If the RCS pressure SL is violated when the reactor is in MODE 1 or 2, the requirement is to restore compliance and be in MODE 3 within 1 hour.

Exceeding the RCS pressure SL may cause immediate RCS failure and create a potential for radioactive releases in excess of 10 CFR 100, "Reactor Site Criteria," limits (Ref. 4).

The allowable Completion Time of 1 hour recognizes the importance of reducing power level to a MODE of operation where the potential for challenges to safety systems is minimized.

If the RCS pressure SL is exceeded in MODE 3, 4, or 5, RCS pressure must be restored to within the SL value within 5 minutes. Exceeding the RCS pressure SL in MODE 3, 4, or 5 is more severe than exceeding this SL in MODE 1 or 2, since the reactor vessel temperature may be lower and the vessel material, consequently, less ductile. As such, pressure must be reduced to less than the SL within 5 minutes. The action does not require reducing MODES, since this would require reducing temperature, which would compound the problem by adding thermal gradient stresses to the existing pressure stress.

BASES

REFERENCES

1. 10 CFR 50, Appendix A.
2. ASME, Boiler and Pressure Vessel Code, Section III, Article NB-7000.50433
3. ASME, Boiler and Pressure Vessel Code, Section XI, Article IWX-5000.
4. 10 CFR 100.
5. FSAR, Section 7.2.
6. USAS B31.1, Standard Code for Pressure Piping, American Society of Mechanical Engineers, 1967.

B 3.0 LIMITING CONDITION FOR OPERATION (LCO) APPLICABILITY

BASES

LCOs	LCO 3.0.1 through LCO 3.0.6 establish the general requirements applicable to all Specifications and apply at all times, unless otherwise stated.

LCO 3.0.1

LCO 3.0.1 establishes the Applicability statement within each individual Specification as the requirement for when the LCO is required to be met (i.e., when the unit is in the MODES or other specified conditions of the Applicability statement of each Specification).

LCO 3.0.2

LCO 3.0.2 establishes that upon discovery of a failure to meet an LCO, the associated ACTIONS shall be met. The Completion Time of each Required Action for an ACTIONS Condition is applicable from the point in time that an ACTIONS Condition is entered. The Required Actions establish those remedial measures that must be taken within specified Completion Times when the requirements of an LCO are not met. This Specification establishes that:

a. Completion of the Required Actions within the specified Completion Times constitutes compliance with a Specification; and

b. Completion of the Required Actions is not required when an LCO is met within the specified Completion Time, unless otherwise specified.

There are two basic types of Required Actions. The first type of Required Action specifies a time limit in which the LCO must be met. This time limit is the Completion Time to restore an inoperable system or component to OPERABLE status or to restore variables to within specified limits. If this type of Required Action is not completed within the specified Completion Time, a shutdown may be required to place the unit in a MODE or condition in which the Specification is not applicable. (Whether stated as a Required Action or not, correction of the entered Condition is

BASES

LCO 3.0.2 (continued)

an action that may always be considered upon entering ACTIONS.) The second type of Required Action specifies the remedial measures that permit continued operation of the unit that is not further restricted by the Completion Time. In this case, compliance with the Required Actions provides an acceptable level of safety for continued operation.

Completing the Required Actions is not required when an LCO is met or is no longer applicable, unless otherwise stated in the individual Specifications.

The nature of some Required Actions of some Conditions necessitates that, once the Condition is entered, the Required Actions must be completed even though the associated Conditions no longer exist. The individual LCO's ACTIONS specify the Required Actions where this is the case. An example of this is in LCO 3.4.3, "RCS Pressure and Temperature (P/T) Limits."

The Completion Times of the Required Actions are also applicable when a system or component is removed from service intentionally. The reasons for intentionally relying on the ACTIONS include, but are not limited to, performance of Surveillances, preventive maintenance, corrective maintenance, or investigation of operational problems. Entering ACTIONS for these reasons must be done in a manner that does not compromise safety. Intentional entry into ACTIONS should not be made for operational convenience. Additionally, if intentional entry into ACTIONS would result in redundant equipment being inoperable, alternatives should be used instead. Doing so limits the time both subsystems/trains of a safety function are inoperable and limits the time conditions exist which may result in LCO 3.0.3 being entered. Individual Specifications may specify a time limit for performing an SR when equipment is removed from service or bypassed for testing. In this case, the Completion Times of the Required Actions are applicable when this time limit expires, if the equipment remains removed from service or bypassed.

When a change in MODE or other specified condition is required to comply with Required Actions, the unit may enter a MODE or other

BASES

LCO 3.0.2 (continued)

specified condition in which another Specification becomes applicable. In this case, the Completion Times of the associated Required Actions would apply from the point in time that the new Specification becomes applicable, and the ACTIONS Condition(s) are entered.

LCO 3.0.3

LCO 3.0.3 establishes the actions that must be implemented when an LCO is not met and:

a. An associated Required Action and Completion Time is not met and no other Condition applies; or

b. The condition of the unit is not specifically addressed by the associated ACTIONS. This means that no combination of Conditions stated in the ACTIONS can be made that exactly corresponds to the actual condition of the unit. Sometimes, possible combinations of Conditions are such that entering LCO 3.0.3 is warranted; in such cases, the ACTIONS specifically state a Condition corresponding to such combinations and also that LCO 3.0.3 be entered immediately.

This Specification delineates the time limits for placing the unit in a safe MODE or other specified condition when operation cannot be maintained within the limits for safe operation as defined by the LCO and its ACTIONS. It is not intended to be used as an operational convenience that permits routine voluntary removal of redundant systems or components from service in lieu of other alternatives that would not result in redundant systems or components being inoperable.

Upon entering LCO 3.0.3, 1 hour is allowed to prepare for an orderly shutdown before initiating a change in unit operation. This includes time to permit the operator to coordinate the reduction in electrical generation with the load dispatcher to ensure the stability and availability of the electrical grid. The time limits specified to reach lower MODES of operation

BASES

LCO 3.0.3 (continued)

permit the shutdown to proceed in a controlled and orderly manner that is well within the specified maximum cooldown rate and within the capabilities of the unit, assuming that only the minimum required equipment is OPERABLE. This reduces thermal stresses on components of the Reactor Coolant System and the potential for a plant upset that could challenge safety systems under conditions to which this Specification applies. The use and interpretation of specified times to complete the actions of LCO 3.0.3 are consistent with the discussion of Section 1.3, Completion Times.

A unit shutdown required in accordance with LCO 3.0.3 may be terminated and LCO 3.0.3 exited if any of the following occurs:

a. The LCO is now met.

b. A Condition exists for which the Required Actions have now been performed.

c. ACTIONS exist that do not have expired Completion Times. These Completion Times are applicable from the point in time that the Condition is initially entered and not from the time LCO 3.0.3 is exited.

The time limits of Specification 3.0.3 allow 37 hours for the unit to be in MODE 5 when a shutdown is required during MODE 1 operation. If the unit is in a lower MODE of operation when a shutdown is required, the time limit for reaching the next lower MODE applies. If a lower MODE is reached in less time than allowed, however, the total allowable time to reach MODE 5, or other applicable MODE, is not reduced. For example, if MODE 3 is reached in 2 hours, then the time allowed for reaching MODE 4 is the next 11 hours, because the total time for reaching MODE 4 is not reduced from the allowable limit of 13 hours. Therefore, if remedial measures are completed that would permit a return to MODE 1, a penalty is not incurred by having to reach a lower MODE of operation in less than the total time allowed.

BASES

LCO 3.0.3 (continued)

In MODES 1, 2, 3, and 4, LCO 3.0.3 provides actions for Conditions not covered in other Specifications. The requirements of LCO 3.0.3 do not apply in MODES 5 and 6 because the unit is already in the most restrictive Condition required by LCO 3.0.3. The requirements of LCO 3.0.3 do not apply in other specified conditions of the Applicability (unless in MODE 1, 2, 3, or 4) because the ACTIONS of individual Specifications sufficiently define the remedial measures to be taken.

Exceptions to LCO 3.0.3 are provided in instances where requiring a unit shutdown, in accordance with LCO 3.0.3, would not provide appropriate remedial measures for the associated condition of the unit. An example of this is in LCO 3.7.14, " Spent Fuel Pit Water Level." LCO 3.7.14 has an Applicability of "During movement of irradiated fuel assemblies in the Spent Fuel Pit." Therefore, this LCO can be applicable in any or all MODES. If the LCO and the Required Actions of LCO 3.7.14 are not met while in MODE 1, 2, or 3, there is no safety benefit to be gained by placing the unit in a shutdown condition. The Required Action of LCO 3.7.14 of "Suspend movement of irradiated fuel assemblies in the Spent Fuel Pit" is the appropriate Required Action to complete in lieu of the actions of LCO 3.0.3. These exceptions are addressed in the individual Specifications.

LCO 3.0.4

LCO 3.0.4 establishes limitations on changes in MODES or other specified conditions in the Applicability when an LCO is not met. It precludes placing the unit in a MODE or other specified condition stated in that Applicability (e.g., Applicability desired to be entered) when the following exist:

a. Unit conditions are such that the requirements of the LCO would not be met in the Applicability desired to be entered; and

b. Continued noncompliance with the LCO requirements, if the Applicability were entered, would result in the unit being

BASES

LCO 3.0.4 (continued)

required to exit the Applicability desired to be entered to comply with the Required Actions.

Compliance with Required Actions that permit continued operation of the unit for an unlimited period of time in a MODE or other specified condition provides an acceptable level of safety for continued operation. This is without regard to the status of the unit before or after the MODE change. Therefore, in such cases, entry into a MODE or other specified condition in the Applicability may be made in accordance with the provisions of the Required Actions. The provisions of this Specification should not be interpreted as endorsing the failure to exercise the good practice of restoring systems or components to OPERABLE status before entering an associated MODE or other specified condition in the Applicability.

The provisions of LCO 3.0.4 shall not prevent changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS. In addition, the provisions of LCO 3.0.4 shall not prevent changes in MODES or other specified conditions in the Applicability that result from any unit shutdown.

Exceptions to LCO 3.0.4 are stated in the individual Specifications. The exceptions allow entry in MODES or other specified conditions in the Applicability when the associated ACTIONS to be entered do not provide for continued operation for a continuous period of time. Exceptions may apply to all the ACTIONS or to a specific Required Action of a Specification.

LCO 3.0.4 is only applicable when entering MODE 4 from MODE 5, MODE 3 from MODE 4, MODE 2 from MODE 3, or MODE 1 from MODE 2. Furthermore, LCO 3.0.4 is applicable when entering any other specified condition in the Applicability only while operating in MODES 1, 2, 3, or 4. The requirements of LCO 3.0.4 do not apply in MODES 5 and 6, or in other specified conditions of the Applicability (unless in MODES 1, 2, 3, or 4) because the ACTIONS of individual Specifications sufficiently define the remedial measures to be taken.

BASES

LCO 3.0.4 (continued)

Surveillances do not have to be performed on the associated inoperable equipment (or on variables outside the specified limits), as permitted by SR 3.0.1. Therefore, changing MODES or other specified conditions while in an ACTIONS Condition, in compliance with LCO 3.0.4 or where an exception to LCO 3.0.4 is stated, is not a violation of SR 3.0.1 or SR 3.0.4 for those Surveillances that do not have to be performed due to the associated inoperable equipment. However, SRs must be met to ensure OPERABILITY prior to declaring the associated equipment OPERABLE (or variable within limits) and restoring compliance with the affected LCO.

LCO 3.0.5

LCO 3.0.5 establishes the allowance for restoring equipment to service under administrative controls when it has been removed from service or declared inoperable to comply with ACTIONS. The sole purpose of this Specification is to provide an exception to LCO 3.0.2 (e.g., to not comply with the applicable Required Action(s)) to allow the performance of required testing to demonstrate:

a. The OPERABILITY of the equipment being returned to service; or

b. The OPERABILITY of other equipment.

The administrative controls ensure the time the equipment is returned to service in conflict with the requirements of the ACTIONS is limited to the time absolutely necessary to perform the required testing to demonstrate OPERABILITY. This Specification does not provide time to perform any other preventive or corrective maintenance.

An example of demonstrating the OPERABILITY of the equipment being returned to service is reopening a containment isolation valve that has been closed to comply with Required Actions and must be reopened to perform the SRs.

BASES

LCO 3.0.5 (continued)

An example of demonstrating the OPERABILITY of other equipment is taking an inoperable channel or trip system out of the tripped condition to prevent the trip function from occurring during the performance of required testing on another channel in the other trip system. A similar example of demonstrating the OPERABILITY of other equipment is taking an inoperable channel or trip system out of the tripped condition to permit the logic to function and indicate the appropriate response during the performance of reqired testing on another channel in the same trip system.

LCO 3.0.6

LCO 3.0.6 establishes an exception to LCO 3.0.2 for support systems that have an LCO specified in the Technical Specifications (TS). This exception is provided because LCO 3.0.2 would require that the Conditions and Required Actions of the associated inoperable supported system LCO be entered solely due to the inoperability of the support system. This exception is justified because the actions that are required to ensure the unit is maintained in a safe condition are specified in the support system LCO's Required Actions. These Required Actions may include entering the supported system's Conditions and Required Actions or may specify other Required Actions.

When a support system is inoperable and there is an LCO specified for it in the TS, the supported system(s) are required to be declared inoperable if determined to be inoperable as a result of the support system inoperability. However, it is not necessary to enter into the supported systems' Conditions and Required Actions unless directed to do so by the support system's Required Actions. The potential confusion and inconsistency of requirements related to the entry into multiple support and supported systems' LCOs' Conditions and Required Actions are eliminated by providing all the actions that are necessary to ensure the unit is maintained in a safe condition in the support system's Required Actions.

However, there are instances where a support system's Required Action may either direct a supported system to be

BASES

LCO 3.0.6 (continued)

declared inoperable or direct entry into Conditions and Required Actions for the supported system. This may occur immediately or after some specified delay to perform some other Required Action. Regardless of whether it is immediate or after some delay, when a support system's Required Action directs a supported system to be declared inoperable or directs entry into Conditions and Required Actions for a supported system, the applicable Conditions and Required Actions shall be entered in accordance with LCO 3.0.2.

Specification 5.5.14, "Safety Function Determination Program (SFDP)," ensures loss of safety function is detected and appropriate actions are taken. Upon entry into LCO 3.0.6, an evaluation shall be made to determine if loss of safety function exists. Additionally, other limitations, remedial actions, or compensatory actions may be identified as a result of the support system inoperability and corresponding exception to entering supported system Conditions and Required Actions. The SFDP implements the requirements of LCO 3.0.6.

Cross train checks to identify a loss of safety function for those support systems that support multiple and redundant safety systems are required. The cross train check verifies that the supported systems of the redundant OPERABLE support system are OPERABLE, thereby ensuring safety function is retained. If this evaluation determines that a loss of safety function exists, the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists are required to be entered.

LCO 3.0.7

There are certain special tests and operations required to be performed at various times over the life of the unit. These special tests and operations are necessary to demonstrate select unit performance characteristics, to perform special maintenance activities, and to perform special evolutions. Test Exception LCOs, such as LCO 3.1.8, allow specified Technical Specification (TS) requirements to be changed to permit performances of these special tests and operations, which otherwise could not be

BASES

LCO 3.0.7 (continued)

performed if required to comply with the requirements of these TS. Unless otherwise specified, all the other TS requirements remain unchanged. This will ensure all appropriate requirements of the MODE or other specified condition not directly associated with or required to be changed to perform the special test or operation will remain in effect.

The Applicability of a Test Exception LCO represents a condition not necessarily in compliance with the normal requirements of the TS. Compliance with Test Exception LCOs is optional. A special operation may be performed either under the provisions of the appropriate Test Exception LCO or under the other applicable TS requirements. If it is desired to perform the special operation under the provisions of the Test Exception LCO, the requirements of the Test Exception LCO shall be followed.

B 3.0 SURVEILLANCE REQUIREMENT (SR) APPLICABILITY

BASES

SRs

SR 3.0.1 through SR 3.0.4 establish the general requirements applicable to all Specifications and apply at all times, unless otherwise stated.

SR 3.0.1

SR 3.0.1 establishes the requirement that SRs must be met during the MODES or other specified conditions in the Applicability for which the requirements of the LCO apply, unless otherwise specified in the individual SRs. This Specification is to ensure that Surveillances are performed to verify the OPERABILITY of systems and components, and that variables are within specified limits. Failure to meet a Surveillance within the specified Frequency, in accordance with SR 3.0.2, constitutes a failure to meet an LCO.

Systems and components are assumed to be OPERABLE when the associated SRs have been met. Nothing in this Specification, however, is to be construed as implying that systems or components are OPERABLE when:

a. The systems or components are known to be inoperable, although still meeting the SRs; or

b. The requirements of the Surveillance(s) are known not to be met between required Surveillance performances.

Surveillances do not have to be performed when the unit is in a MODE or other specified condition for which the requirements of the associated LCO are not applicable, unless otherwise specified. The SRs associated with a test exception are only applicable when the test exception is used as an allowable exception to the requirements of a Specification.

Unplanned events may satisfy the requirements (including applicable acceptance criteria) for a given SR. In this case, the unplanned event may be credited as fulfilling the performance of the SR. This allowance includes those SRs whose performance

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BASES

SR 3.0.1 (continued)

is norally precluded in a given MODE or other specified condition.

Surveillances, including Surveillances invoked by Required Actions, do not have to be performed on inoperable equipment because the ACTIONS define the remedial measures that apply. Surveillances have to be met and performed in accordance with SR 3.0.2, prior to returning equipment to OPERABLE status.

Upon completion of maintenance, appropriate post maintenance testing is required to declare equipment OPERABLE. This includes ensuring applicable Surveillances are not failed and their most recent performance is in accordance with SR 3.0.2. Post maintenance testing may not be possible in the current MODE or other specified conditions in the Applicability due to the necessary unit parameters not having been established. In these situations, the equipment may be considered OPERABLE provided testing has been satisfactorily completed to the extent possible and the equipment is not otherwise believed to be incapable of performing its function. This will allow operation to proceed to a MODE or other specified condition where other necessary post maintenance tests can be completed.

SR 3.0.2

SR 3.0.2 establishes the requirements for meeting the specified Frequency for Surveillances and any Required Action with a Completion Time that requires the periodic performance of the Required Action on a "once per . . ." interval.

SR 3.0.2 permits a 25% extension of the interval specified in the Frequency. This extension facilitates Surveillance scheduling and considers plant operating conditions that may not be suitable for conducting the Surveillance (e.g., transient conditions or other ongoing Surveillance or maintenance activities).

The 25% extension does not significantly degrade the reliability that results from performing the Surveillance at its specified Frequency. This is based on the recognition that the most probable result of any particular Surveillance being performed is

BASES

SR 3.0.2 (continued)

the verification of conformance with the SRs. The exceptions to SR 3.0.2 are those Surveillances for which the 25% extension of the interval specified in the Frequency does not apply. These exceptions are stated in the individual Specifications. An example of where SR 3.0.2 does not apply is a Surveillance with a Frequency of "in accordance with 10 CFR 50, Appendix J, as modified by approved exemptions." The requirements of regulations take precedence over the TS. The TS cannot in and of themselves extend a test interval specified in the regulations. Therefore, there is a Note in the Frequency stating, "SR 3.0.2 is not applicable."

As stated in SR 3.0.2, the 25% extension also does not apply to the initial portion of a periodic Completion Time that requires performance on a "once per ..." basis. The 25% extension applies to each performance after the initial performance. The initial performance of the Required Action, whether it is a particular Surveillance or some other remedial action, is considered a single action with a single Completion Time. One reason for not allowing the 25% extension to this Completion Time is that such an action usually verifies that no loss of function has occurred by checking the status of redundant or diverse components or accomplishes the function of the inoperable equipment in an alternative manner.

The provisions of SR 3.0.2 are not intended to be used repeatedly merely as an operational convenience to extend Surveillance intervals (other than those consistent with refueling intervals) or periodic Completion Time intervals beyond those specified.

SR 3.0.3

SR 3.0.3 establishes the flexibility to defer declaring affected equipment inoperable or an affected variable outside the specified limits when a Surveillance has not been completed within the specified Frequency. A delay period of up to 24 hours or up to the limit of the specified Frequency, whichever is less, applies from the point in time that it is discovered that the

BASES

SR 3.0.3 (continued)

Surveillance has not been performed in accordance with SR 3.0.2, and not at the time that the specified Frequency was not met.

This delay period provides adequate time to complete Surveillances that have been missed. This delay period permits the completion of a Surveillance before complying with Required Actions or other remedial measures that might preclude completion of the Surveillance.

The basis for this delay period includes consideration of unit conditions, adequate planning, availability of personnel, the time required to perform the Surveillance, the safety significance of the delay in completing the required Surveillance, and the recognition that the most probable result of any particular Surveillance being performed is the verification of conformance with the requirements. When a Surveillance with a Frequency based not on time intervals, but upon specified unit conditions or operational situations, is discovered not to have been performed when specified, SR 3.0.3 allows the full delay period of 24 hours to perform the Surveillance.

SR 3.0.3 also provides a time limit for completion of Surveillances that become applicable as a consequence of MODE changes imposed by Required Actions.

Failure to comply with specified Frequencies for SRs is expected to be an infrequent occurrence. Use of the delay period established by SR 3.0.3 is a flexibility which is not intended to be used as an operational convenience to extend Surveillance intervals.

If a Surveillance is not completed within the allowed delay period, then the equipment is considered inoperable or the variable is considered outside the specified limits and the Completion Times of the Required Actions for the applicable LCO Conditions begin immediately upon expiration of the delay period. If a Surveillance is failed within the delay period, then the equipment is inoperable, or the variable is outside the specified

BASES

SR 3.0.3 (continued)

limits and the Completion Times of the Required Actions for the applicable LCO Conditions begin immediately upon the failure of the Surveillance.

Completion of the Surveillance within the delay period allowed by this Specification, or within the Completion Time of the ACTIONS, restores compliance with SR 3.0.1.

SR 3.0.4

SR 3.0.4 establishes the requirement that all applicable SRs must be met before entry into a MODE or other specified condition in the Applicability.

This Specification ensures that system and component OPERABILITY requirements and variable limits are met before entry into MODES or other specified conditions in the Applicability for which these systems and components ensure safe operation of the unit.

The provisions of this Specification should not be interpreted as endorsing the failure to exercise the good practice of restoring systems or component to OPERABLE status before entering an associated MODE or other specified condition in the Applicability.

However, in certain circumstances, failing to meet an SR will not result in SR 3.0.4 restricting a MODE change or other specified condition change. When a system, subsystem, division, component, device, or variable is inoperable or outside its specified limits, the associated SR(s) are not required to be performed, per SR 3.0.1, which states that surveillances do not have to be performed on inoperable equipment. When equipment is inoperable, SR 3.0.4 does not apply to the associated SR(s) since the requirement for the SR(s) to be performed is removed. Therefore, failing to perform the Surveillance(s) within the specified Frequency does not result in an SR 3.0.4 restriction to changing MODES or other specified conditions of the Applicability. However, since the LCO is not met in this instance, LCO 3.0.4

BASES

SR 3.0.4 (continued)

will govern any restrictions that may (or may not) apply to MODE or other specified condition changes.

The provisions of SR 3.0.4 shall not prevent changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS. In addition, the provisions of LCO 3.0.4 shall not prevent changes in MODES or other specified conditions in the Applicability that result from any unit shutdown.

The precise requirements for performance of SRs are specified such that exceptions to SR 3.0.4 are not necessary. The specific time frames and conditions necessary for meeting the SRs are specified in the Frequency, in the Surveillance, or both. This allows performance of Surveillances when the prerequisite condition(s) specified in a Surveillance procedure require entry into the MODE or other specified condition in the Applicability of the associated LCO prior to the performance or completion of a Surveillance. A Surveillance that could not be performed until after entering the LCO Applicability, would have its Frequency specified such that it is not "due" until the specific conditions needed are met. Alternately, the Surveillance may be stated in the form of a Note as not required (to be met or performed) until a particular event, condition, or time has been reached. Further discussion of the specific formats of SRs' annotation is found in Section 1.4, Frequency.

SR 3.0.4 is only applicable when entering MODE 4 from MODE 5, MODE 3 from MODE 4, Mode 2 from MODE 3, or MODE 1 from MODE 2. Furthermore, SR 3.0.4 is applicable when entering any other specified condition in the Applicability only while operating in MODES 1, 2, 3, or 4. The requirements of SR 3.0.4 do not apply in MODES 5 and 6, or in other specified conditions of the Applicability (unless in MODES 1, 2, 3, or 4) because the ACTIONS of individual Specifications sufficiently define the remedial measures to be taken.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.1 SHUTDOWN MARGIN (SDM)

BASES

BACKGROUND

According to GDC 26 (Ref. 1), the reactivity control systems must be redundant and capable of holding the reactor core subcritical when shut down under cold conditions. Maintenance of the SDM ensures that postulated reactivity events will not damage the fuel.

SDM requirements provide sufficient reactivity margin to ensure that acceptable fuel design limits will not be exceeded for normal shutdown and anticipated operational occurrences (AOOs). As such, the SDM defines the degree of subcriticality that would be obtained immediately following the insertion or scram of all shutdown and control rods, assuming that the single rod cluster assembly of highest reactivity worth is fully withdrawn.

The system design requires that two independent reactivity control systems be provided, and that one of these systems be capable of maintaining the core subcritical under cold conditions. These requirements are provided by the use of movable control assemblies and soluble boric acid in the Reactor Coolant System (RCS). The Control Rod System can compensate for the reactivity effects of the fuel and water temperature changes accompanying power level changes over the range from full load to no load. In addition, the Control Rod System, together with the boration system, provides the SDM during power operation and is capable of making the core subcritical rapidly enough to prevent exceeding acceptable fuel damage limits, assuming that the rod of highest reactivity worth remains fully withdrawn. The soluble boron system can compensate for fuel depletion during operation and all xenon burnout reactivity changes and maintain the reactor subcritical under cold conditions.

During power operation, SDM control is ensured by operating with the shutdown banks within the limits of LCO 3.1.5, "Shutdown Bank Insertion Limits" and the control banks within the limits of LCO 3.1.6, "Control Bank Insertion Limits." When the unit is in the shutdown and refueling modes, the SDM requirements are met by means of adjustments to the RCS boron concentration.

BASES

APPLICABLE SAFETY ANALYSES

The minimum required SDM is assumed as an initial condition in safety analyses. The safety analysis (Ref. 2) establishes an SDM that ensures specified acceptable fuel design limits are not exceeded for normal operation and AOOs, with the assumption of the highest worth rod stuck out on scram. For MODE 5, the primary safety analysis that relies on the SDM limit is the boron dilution analysis.

The acceptance criteria for the SDM requirements are that specified acceptable fuel design limits are maintained. This is done by ensuring that:

a. The reactor can be made subcritical from all operating conditions, transients, and Design Basis Events;

b. The reactivity transients associated with postulated accident conditions are controllable within acceptable limits (departure from nucleate boiling ratio (DNBR), fuel centerline temperature limits for AOOs, and energy deposition of ≤ 250 cal/gm for non-irradiated fuel and ≤ 200 cal/gm for irradiated fuel to satisfy requirements for the rod ejection accident); and

c. The reactor will be maintained sufficiently subcritical to preclude inadvertent criticality in the shutdown condition.

The most limiting accident for the SDM requirements is based on a main steam line break (MSLB), as described in the accident analysis (Ref. 2). The increased steam flow resulting from a pipe break in the main steam system causes an increased energy removal from the affected steam generator (SG), and consequently the RCS. This results in a reduction of the reactor coolant temperature. The resultant coolant shrinkage causes a reduction in pressure. In the presence of a negative moderator temperature coefficient, this cooldown causes an increase in core reactivity. As RCS temperature decreases, the severity of an MSLB decreases until the MODE 5 value is reached. The most limiting MSLB, with respect to potential fuel damage before a reactor trip occurs, is a guillotine break of a main steam line inside containment

BASES

APPLICABLE SAFETY ANALYSES (continued)

initiated at the end of core life. The positive reactivity addition from the moderator temperature decrease will terminate when the affected SG boils dry, thus terminating RCS heat removal and cooldown. Following the MSLB, a post trip return to power may occur; however, no fuel damage occurs as a result of the post trip return to power, and THERMAL POWER does not violate the Safety Limit (SL) requirement of SL 2.1.1.

In addition to the limiting MSLB transient, the SDM requirement must also protect against:

a. Inadvertent boron dilution;

b. An uncontrolled rod withdrawal from subcritical or low power condition;

c. Startup of an inactive reactor coolant pump (RCP); and

d. Rod ejection.

Each of these events is discussed below.

In the boron dilution analysis, the required SDM defines the reactivity difference between an initial subcritical boron concentration and the corresponding critical boron concentration. These values, in conjunction with the configuration of the RCS and the assumed dilution flow rate, directly affect the results of the analysis. This event is most limiting at the beginning of core life, when critical boron concentrations are highest.

Depending on the system initial conditions and reactivity insertion rate, the uncontrolled rod withdrawal transient is terminated by either a high neutron flux level trip or a overtemperature ΔT trip. In all cases, power level, RCS pressure, linear heat rate, and the DNBR do not exceed allowable limits.

The startup of an inactive RCP will not result in a "cold water" criticality, even if the maximum difference in temperature exists

BASES

APPLICABLE SAFETY ANALYSES (continued)

between the SG and the core. The maximum positive reactivity addition that can occur due to an inadvertent RCP start is less than the minimum required SDM. Startup of an idle RCP cannot, therefore, produce a return to power from the hot standby condition.

The ejection of a control rod rapidly adds reactivity to the reactor core, causing both the core power level and heat flux to increase with corresponding increases in reactor coolant temperatures and pressure. The ejection of a rod also produces a time dependent redistribution of core power.

SDM satisfies Criterion 2 of 10 CFR 50.36. Even though it is not directly observed from the control room, SDM is considered an initial condition process variable because it is periodically monitored to ensure that the unit is operating within the bounds of accident analysis assumptions.

LCO

SDM is a core design condition that can be ensured during operation through control rod positioning (control and shutdown banks) and through the soluble boron concentration.

The MSLB (Ref. 2) and the boron dilution (Ref. 2) accidents are the most limiting analyses that establish the SDM value of the LCO. For MSLB accidents, if the LCO is violated, there is a potential to exceed the DNBR limit and to exceed 10 CFR 100, "Reactor Site Criteria," limits (Ref. 3). For the boron dilution accident, if the LCO is violated, the minimum required time assumed for operator action to terminate dilution may no longer be applicable.

APPLICABILITY

In MODE 2 with k_{eff} < 1.0 and in MODES 3, 4,and 5, the SDM requirements are applicable to provide sufficient negative reactivity to meet the assumptions of the safety analyses discussed above. In MODE 6, the shutdown reactivity requirements

BASES

APPLICABILITY (continued)

are given in LCO 3.9.1, "Boron Concentration." In MODES 1 and 2, SDM is ensured by complying with LCO 3.1.5, "Shutdown Bank Insertion Limits," and LCO 3.1.6, Control Bank Insertion Limits.

ACTIONS

A.1

If the SDM requirements are not met, boration must be initiated promptly. A Completion Time of 15 minutes is adequate for an operator to correctly align and start the required systems and components. It is assumed that boration will be continued until the SDM requirements are met.

In the determination of the required combination of boration flow rate and boron concentration, there is no unique requirement that must be satisfied. Since it is imperative to raise the boron concentration of the RCS as soon as possible, the boron concentration should be a highly concentrated solution, such as that normally found in the boric acid storage tank, or the refueling water storage tank. The operator should borate with the best source available for the plant conditions.

SURVEILLANCE REQUIREMENTS

SR 3.1.1.1

In MODES 1 and 2, SDM is verified by observing that the requirements of LCO 3.1.5 and LCO 3.1.6 are met. In the event that a rod is known to be untrippable, however, SDM verification must account for the worth of the untrippable rod as well as another rod of maximum worth.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.1.1 (continued)

In MODES 3, 4, and 5, the SDM is verified by performing a reactivity balance calculation, considering the listed reactivity effects:

a. RCS boron concentration;

b. Control bank position;

c. RCS average loop temperature;

d. Fuel burnup based on gross thermal energy generation;

e. Xenon concentration;

f. Samarium concentration; and

g. Isothermal temperature coefficient (ITC).

Using the ITC accounts for Doppler reactivity in this calculation because the reactor is subcritical, and the fuel temperature will be changing at the same rate as the RCS.

The Frequency of 24 hours is based on the generally slow change in required boron concentration and the low probability of an accident occurring without the required SDM. This allows time for the operator to collect the required data, which includes performing a boron concentration analysis, and complete the calculation.

BASES

REFERENCES

1. 10 CFR 50, Appendix A, GDC 26.
2. FSAR, Chapter 14.
3. 10 CFR 100.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.2 Core Reactivity

BASES

BACKGROUND

According to GDC 26, GDC 28, and GDC 29 (Ref. 1), reactivity shall be controllable, such that subcriticality is maintained under cold conditions, and acceptable fuel design limits are not exceeded during normal operation and anticipated operational occurrences. Therefore, reactivity balance is used as a measure of the predicted versus measured core reactivity during power operation. The periodic confirmation of core reactivity is necessary to ensure that Design Basis Accident (DBA) and transient safety analyses remain valid. A large reactivity difference could be the result of unanticipated changes in fuel, control rod worth, or operation at conditions not consistent with those assumed in the predictions of core reactivity, and could potentially result in a loss of SDM or violation of acceptable fuel design limits. Comparing predicted versus measured core reactivity validates the nuclear methods used in the safety analysis and supports the SDM demonstrations (LCO 3.1.1. "SHUTDOWN MARGIN (SDM)") in ensuring the reactor can be brought safely to cold, subcritical conditions.

When the reactor core is critical or in normal power operation, a reactivity balance exists and the net reactivity is zero. A comparison of predicted and measured reactivity is convenient under such a balance, since parameters are being maintained relatively stable under steady state power conditions. The positive reactivity inherent in the core design is balanced by the negative reactivity of the control components, thermal feedback, neutron leakage, and materials in the core that absorb neutrons, such as burnable absorbers producing zero net reactivity. Excess reactivity can be inferred from the boron letdown curve (or critical boron curve), which provides an indication of the soluble boron concentration in the Reactor Coolant System (RCS) versus cycle burnup. Periodic measurement of the RCS boron concentration for comparison with the predicted value with other variables fixed (such as rod height, temperature, pressure, and power), provides a convenient method of ensuring that core reactivity is within design expectations

BASES

BACKGROUND (continued)

and that the calculational models used to generate the safety analysis are adequate.

In order to achieve the required fuel cycle energy output, the uranium enrichment, in the new fuel loading and in the fuel remaining from the previous cycle, provides excess positive reactivity beyond that required to sustain steady state operation throughout the cycle. When the reactor is critical at RTP and moderator temperature, the excess positive reactivity is compensated by burnable absorbers (if any), control rods, whatever neutron poisons (mainly xenon and samarium) are present in the fuel, and the RCS boron concentration.

When the core is producing THERMAL POWER, the fuel is being depleted and excess reactivity is decreasing. As the fuel depletes, the RCS boron concentration is reduced to decrease negative reactivity and maintain constant THERMAL POWER. The boron letdown curve is based on steady state operation at RTP. Therefore, deviations from the predicted boron letdown curve may indicate deficiencies in the design analysis, deficiencies in the calculational models, or abnormal core conditions, and must be evaluated.

APPLICABLE SAFETY ANALYSES

The acceptance criteria for core reactivity are that the reactivity balance limit ensures plant operation is maintained within the assumptions of the safety analyses.

Accurate prediction of core reactivity is either an explicit or implicit assumption in the accident analysis evaluations. Accident evaluations (Ref. 2) are, therefore, dependent upon accurate evaluation of core reactivity. In particular, SDM and reactivity transients, such as control rod withdrawal accidents or rod ejection accidents, are very sensitive to accurate prediction of core reactivity. These accident analysis evaluations rely on computer codes that have been qualified

BASES

APPLICABLE SAFETY ANALYSES (continued)

against available test data, operating plant data, and analytical benchmarks. Monitoring reactivity balance additionally ensures that the nuclear methods provide an accurate representation of the core reactivity.

Design calculations and safety analyses are performed for each fuel cycle for the purpose of predetermining reactivity behavior and the RCS boron concentration requirements for reactivity control during fuel depletion.

The comparison between measured and predicted initial core reactivity provides a normalization for the calculational models used to predict core reactivity. If the measured and predicted RCS boron concentrations for identical core conditions at beginning of cycle (BOL) do not agree to within specified limits, then the assumptions used in the reload cycle design analysis or the calculational models used to predict soluble boron requirements may not be accurate. If reasonable agreement between measured and predicted core reactivity exists at BOL, then the prediction may be normalized to the measured boron concentration. Thereafter, any significant deviations in the measured boron concentration from the predicted boron letdown curve that develop during fuel depletion may be an indication that the calculational model is not adequate for core burnups beyond BOL, or that an unexpected change in core conditions has occurred.

The normalization of predicted RCS boron concentration to the measured value is typically performed after reaching RTP following startup from a refueling outage, with the control rods in their normal positions for power operation. The normalization is performed at BOL conditions, so that core reactivity relative to predicted values can be continually monitored and evaluated as core conditions change during the cycle.

Core reactivity satisfies Criterion 2 of 10 CFR 50.36.

BASES

LCO

This LCO requires that measured core reactivity is within ± 1% Δk/k of predicted values. During steady state power operation, this comparison includes reactor coolant system boron concentration, control rod position, reactor coolant system average loop temperature, fuel burnup based on gross thermal energy generation, xenon concentration, and samarium concentration.

Long term core reactivity behavior is a result of the core physics design and cannot be easily controlled once the core design is fixed. During operation, therefore, the LCO can only be ensured through measurement and tracking, and appropriate actions taken as necessary. Large differences between actual and predicted core reactivity may indicate that the assumptions of the DBA and transient analyses are no longer valid, or that the uncertainties in the Nuclear Design Methodology are larger than expected. A limit on the reactivity balance of ± 1% Δk/k has been established based on engineering judgment. A 1% deviation in reactivity from that predicted is larger than expected for normal operation and should therefore be evaluated.

When measured core reactivity is within 1% Δk/k of the predicted value at steady state thermal conditions, the core is considered to be operating within acceptable design limits. Since deviations from the limit are normally detected by comparing predicted and measured steady state RCS critical boron concentrations, the difference between measured and predicted values would be approximately 100 ppm (depending on the boron worth) before the limit is reached. These values are well within the uncertainty limits for analysis of boron concentration samples, so that spurious violations of the limit due to uncertainty in measuring the RCS boron concentration are unlikely.

APPLICABILITY

The limits on core reactivity must be maintained during MODE 1 because a reactivity balance must exist when the reactor is critical and producing THERMAL POWER. As the fuel depletes, core conditions are changing, and confirmation of the reactivity balance ensures the core is operating as designed. This Specification does not apply in MODE 2 because enough operating

BASES

APPLICABILITY (continued)

margin exists to limit the effects of a reactivity anomaly, and THERMAL POWER is low enough (≤5% RTP) such that reactivity anomalies are unlikely to occur. This Specification does not apply in MODES 3, 4, and 5 because the reactor is shut down and the reactivity balance is not changing.

In MODE 6, fuel loading results in a continually changing core reactivity. Boron concentration requirements (LCO 3.9.1, "Boron Concentration") ensure that fuel movements are performed within the bounds of the safety analysis. An SDM demonstration is required during the first startup following operations that could have altered core reactivity (e.g., fuel movement, control rod replacement, control rod shuffling).

ACTIONS

A.1 and A.2

Should an anomaly develop between measured and predicted core reactivity, an evaluation of the core design and safety analysis must be performed. Core conditions are evaluated to determine their consistency with input to design calculations. Measured core and process parameters are evaluated to determine that they are within the bounds of the safety analysis, and safety analysis calculational models are reviewed to verify that they are adequate for representation of the core conditions. The required Completion Time of 7 days is based on the low probability of a DBA occurring during this period, and allows sufficient time to assess the physical condition of the reactor and complete the evaluation of the core design and safety analysis.

Following evaluations of the core design and safety analysis, the cause of the reactivity anomaly may be resolved. If the cause of the reactivity anomaly is a mismatch in core conditions at the time of RCS boron concentration sampling, then a recalculation of the RCS boron concentration requirements may be performed to demonstrate that core reactivity is behaving as expected. If an unexpected physical change in the condition of the core has occurred, it must be evaluated and corrected, if possible. If the cause of the reactivity anomaly is in the calculation technique, then the calculational models must be revised to

BASES

ACTIONS

A.1 and A.2 (continued)

provide more accurate predictions. If any of these results are demonstrated, and it is concluded that the reactor core is acceptable for continued operation, then the boron letdown curve may be renormalized and power operation may continue. If operational restriction or additional SRs are necessary to ensure the reactor core is acceptable for continued operation, then they must be defined.

The required Completion Time of 7 days is adequate for preparing whatever operating restrictions or Surveillances that may be required to allow continued reactor operation.

B.1

If the core reactivity cannot be restored to within the 1% $\Delta k/k$ limit, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 2 within 6 hours. The allowed Completion Time is reasonable, based on operating experience, for reaching MODE 2 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.2.1

Core reactivity is verified by periodic comparisons of measured and predicted RCS boron concentrations. The comparison is made during steady state operation because other core conditions are fixed or stable, including control rod position, moderator temperature, fuel temperature, fuel depletion, xenon concentration, and samarium concentration. The Surveillance is also performed during physics testing following refueling as an initial check on core conditions and design calculations at BOL. The SR is modified by a Note. The Note indicates that the normalization of predicted core reactivity to the measured value, if performed, must take place within the first 60 effective full power days (EFPD) after each fuel loading. This allows sufficient time for core conditions to reach steady state, but

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.2.1 (continued)

prevents operation for a large fraction of the fuel cycle without establishing a benchmark for the design calculations. The required subsequent Frequency of 31 EFPD based on the slow rate of core changes due to fuel depletion and the presence of other indicators (QPTR, AFD, etc.) for prompt indication of an anomaly. As specified in a Note to the FREQUENCY, the inital performance of the SR in MODE 1 after refueling is not required until 60 EFPDs after entering MODE 1.

REFERENCES

1. 10 CFR 50, Appendix A.

2. FSAR, Chapter 14.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.3 Moderator Temperature Coefficient (MTC)

BASES

BACKGROUND

According to GDC 11 (Ref. 1), the reactor core and its interaction with the Reactor Coolant System (RCS) must be designed for inherently stable power operation, even in the possible event of an accident. In particular, the net reactivity feedback in the system must compensate for any unintended reactivity increases.

The MTC relates a change in core reactivity to a change in reactor coolant temperature (a positive MTC means that reactivity increases with increasing moderator temperature; conversely, a negative MTC means that reactivity decreases with increasing moderator temperature). The reactor is designed to operate with a negative MTC over the largest possible range of fuel cycle operation. Therefore, a coolant temperature increase will cause a reactivity decrease, so that the coolant temperature tends to return toward its initial value. Reactivity increases that cause a coolant temperature increase will thus be self limiting, and stable power operation will result.

MTC values are predicted at selected burnups during the safety evaluation analysis and are confirmed to be acceptable by measurements. Both initial and reload cores are designed so that the beginning of life (BOL) MTC is less than zero when THERMAL POWER is at RTP. The actual value of the MTC is dependent on core characteristics, such as fuel loading and reactor coolant soluble boron concentration. The core design may require additional fixed distributed poisons to yield an MTC at BOL within the range analyzed in the plant accident analysis. The end of life (EOL) MTC is also limited by the requirements of the accident analysis. Fuel cycles that are designed to achieve high burnups or that have changes to other characteristics are evaluated to ensure that the MTC does not exceed the EOL limit.

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

BASES

BACKGROUND (continued)

If the LCO limits are not met, the unit response during transients may not be as predicted. The core could violate criteria that prohibit a return to criticality, or the departure from nucleate boiling ratio criteria of the approved correlation may be violated, which could lead to a loss of the fuel cladding integrity.

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

APPLICABLE SAFETY ANALYSES

The acceptance criteria for the specified MTC are:

a. The MTC values must remain within the bounds of those used in the accident analysis (Ref. 2); and

b. The MTC must be such that inherently stable power operations result during normal operation and accidents, such as overheating and overcooling events.

The FSAR, Chapter 14 (Ref. 2), contains analyses of accidents that result in both overheating and overcooling of the reactor core. MTC is one of the controlling parameters for core reactivity in these accidents. Both the most positive value and most negative value of the MTC are important to safety, and both values must be bounded. Values used in the analyses consider worst case conditions to ensure that the accident results are bounding (Ref. 3).

The consequences of accidents that cause core overheating must be evaluated when the MTC is positive. Such accidents include the rod withdrawal transient from either zero (Ref. 2) or RTP, loss of main feedwater flow, and loss of forced reactor coolant flow. The consequences of accidents that cause core overcooling must be

BASES

APPLICABLE SAFETY ANALYSES (continued)

evaluated when the MTC is negative. Such accidents include sudden feedwater flow increase and sudden decrease in feedwater temperature.

In order to ensure a bounding accident analysis, the MTC is assumed to be its most limiting value for the analysis conditions appropriate to each accident. The bounding value is determined by considering rodded and unrodded conditions, whether the reactor is at full or zero power, and whether it is the BOL or EOL. The most conservative combination appropriate to the accident is then used for the analysis (Ref. 2).

MTC values are bounded in reload safety evaluations assuming steady state conditions at BOL and EOL. An EOL measurement is conducted at conditions when the RCS boron concentration reaches approximately 300 ppm. The measured value may be extrapolated to project the EOL value, in order to confirm reload design predictions.

MTC satisfies Criterion 2 of 10 CFR 50.36. Even though it is not directly observed and controlled from the control room, MTC is considered an initial condition process variable because of its dependence on boron concentration.

LCO

LCO 3.1.3 requires the MTC to be within specified limits of the COLR to ensure that the core operates within the assumptions of the accident analysis. During the reload core safety evaluation, the MTC is analyzed to determine that its values remain within the bounds of the original accident analysis during operation.

Assumptions made in safety analyses require that the MTC be less positive than a given upper bound and more positive than a given lower bound. The MTC is most positive at BOL; this upper bound must not be exceeded. This maximum upper limit occurs at BOL, all rods out (ARO), hot zero power conditions. At EOL the MTC takes on its most negative value, when the lower bound becomes important. This LCO exists to ensure that both the upper and lower bounds are not exceeded.

BASES

LCO (continued)

During operation, therefore, the conditions of the LCO can only be ensured through measurement. The Surveillance checks at BOL and EOL on MTC provide confirmation that the MTC is behaving as anticipated so that the acceptance criteria are met.

The LCO establishes a maximum positive value that cannot be exceeded. The BOL positive limit and the EOL negative limit are established in the COLR to allow specifying limits for each particular cycle. This permits the unit to take advantage of improved fuel management and changes in unit operating schedule.

APPLICABILITY

Technical Specifications place both LCO and SR values on MTC, based on the safety analysis assumptions described above.

In MODE 1, the limits on MTC must be maintained to ensure that any accident initiated from THERMAL POWER operation will not violate the design assumptions of the accident analysis. In MODE 2 with the reactor critical, the upper limit must also be maintained to ensure that startup and subcritical accidents (such as the uncontrolled CONTROL ROD assembly or group withdrawal) will not violate the assumptions of the accident analysis. The lower MTC limit must be maintained in MODES 2 and 3, in addition to MODE 1, to ensure that cooldown accidents will not violate the assumptions of the accident analysis. In MODES 4, 5, and 6, this LCO is not applicable, since no Design Basis Accidents using the MTC as an analysis assumption are initiated from these MODES.

ACTIONS

A.1

If the BOL MTC limit is violated, administrative withdrawal limits for control banks must be established to maintain the MTC within its limits. The MTC becomes more negative with control bank insertion and decreased boron concentration. A Completion Time of 24 hours provides enough time for evaluating the MTC measurement and computing the required bank withdrawal limits.

BASES

ACTIONS

A.1 (continued)

As cycle burnup is increased, the RCS boron concentration will be reduced. The reduced boron concentration causes the MTC to become more negative. Using physics calculations, the time in cycle life at which the calculated MTC will meet the LCO requirement can be determined. At this point in core life Condition A no longer exists. The unit is no longer in the Required Action, so the administrative withdrawal limits are no longer in effect.

B.1

If the required administrative withdrawal limits at BOL are not established within 24 hours, the unit must be brought to MODE 2 with $k_{eff} < 1.0$ to prevent operation with an MTC that is more positive than that assumed in safety analyses.

The allowed Completion Time of 6 hours is reasonable, based on operating experience, for reaching the required MODE from full power conditions in an orderly manner and without challenging plant systems.

C.1

Exceeding the EOL MTC limit means that the safety analysis assumptions for the EOL accidents that use a bounding negative MTC value may be invalid. If the EOL MTC limit is exceeded, the plant must be brought to a MODE or condition in which the LCO requirements are not applicable. To achieve this status, the unit must be brought to at least MODE 4 within 12 hours.

The allowed Completion Time is reasonable, based on operating experience, for reaching the required MODE from full power conditions in an orderly manner and without challenging plant systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.3.1

This SR requires measurement of the MTC at BOL prior to entering MODE 1 in order to demonstrate compliance with the most positive MTC LCO. Meeting the limit prior to entering MODE 1 ensures that the limit will also be met at higher power levels.

The BOL MTC value for ARO will be inferred from isothermal temperature coefficient measurements obtained during the physics tests after refueling. The ARO value can be directly compared to the BOL MTC limit of the LCO. If required, measurement results and predicted design values can be used to establish administrative withdrawal limits for control banks.

SR 3.1.3.2

In similar fashion, the LCO demands that the MTC be less negative than the specified value for EOL full power conditions. This measurement may be performed at any THERMAL POWER, but its results must be extrapolated to the conditions of RTP and all banks withdrawn in order to make a proper comparison with the LCO value. Because the RTP MTC value will gradually become more negative with further core depletion and boron concentration reduction, a 300 ppm SR value of MTC should necessarily be less negative than the EOL LCO limit. The 300 ppm SR value is sufficiently less negative than the EOL LCO limit value to ensure that the LCO limit will be met when the 300 ppm Surveillance criterion is met.

SR 3.1.3.2 is modified by three Notes that include the following requirements:

1. This SR is not required to be performed until 7 effective full power days (EFPD) after reaching the equivalent of an equilibrium RTP all rods out (ARO) boron concentration of 300 ppm.

2. If the 300 ppm Surveillance limit is exceeded, it is possible that the EOL limit on MTC could be reached before the planned EOL. Because the MTC changes slowly with core

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.3.2 (continued)

depletion, the Frequency of 14 effective full power days is sufficient to avoid exceeding the EOL limit.

3. The Surveillance limit for RTP boron concentration of 60 ppm is conservative. If the measured MTC at 60 ppm is more positive than the 60 ppm Surveillance limit, the EOL limit will not be exceeded because of the gradual manner in which MTC changes with core burnup.

REFERENCES

1. 10 CFR 50, Appendix A.

2. FSAR, Chapter 14.

3. WCAP 9273-NP-A, "Westinghouse Reload Safety Evaluation Methodology," July 1985.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.4 Rod Group Alignment Limits

BASES

BACKGROUND

The OPERABILITY (i.e., trippability) of the shutdown and control rods is an initial assumption in all safety analyses that assume rod insertion upon reactor trip. Maximum rod misalignment is an initial assumption in the safety analysis that directly affects core power distributions and assumptions of available SDM.

The applicable criteria for these reactivity and power distribution design requirements are GDC 10, "Reactor Design," GDC 26, "Reactivity Control System Redundancy and Protection" (Ref. 1), and 10 CFR 50.46, "Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Plants" (Ref. 2).

Mechanical or electrical failures may cause a control rod to become inoperable or to become misaligned from its group. Control rod inoperability or misalignment may cause increased power peaking, due to the asymmetric reactivity distribution and a reduction in the total available rod worth for reactor shutdown. Therefore, control rod alignment and OPERABILITY are related to core operation in design power peaking limits and the core design requirement of a minimum SDM.

Limits on control rod alignment have been established, and all rod positions are monitored and controlled during power operation to ensure that the power distribution and reactivity limits defined by the design power peaking and SDM limits are preserved.

Rod cluster control assemblies (RCCAs), or rods, are moved by their control rod drive mechanisms (CRDMs). Each CRDM moves its RCCA one step (approximately ⅝ inch) at a time, but at varying rates (steps per minute) depending on the signal output from the Rod Control System.

The RCCAs are divided among control banks and shutdown banks. Each bank may be further subdivided into two groups to provide for precise reactivity control. A group consists of two or more

BASES

BACKGROUND (continued)

RCCAs that are electrically paralleled to step simultaneously. A bank of RCCAs may consist of two groups that are moved in a staggered fashion, but always within one step of each other. IP3 has four control banks and four shutdown banks.

The shutdown banks are maintained either in the fully inserted or fully withdrawn position. The control banks are moved in an overlap pattern, using the following withdrawal sequence: When control bank A reaches a predetermined height in the core, control bank B begins to move out with control bank A. Control bank A stops at the position of maximum withdrawal, and control bank B continues to move out. When control bank B reaches a predetermined height, control bank C begins to move out with control bank B. This sequence continues until control banks A, B, and C are at the fully withdrawn position, and control bank D is at the desired position. The insertion sequence is the opposite of the withdrawal sequence. The control rods are arranged in a radially symmetric pattern, so that control bank motion does not introduce radial asymmetries in the core power distributions.

The axial position of shutdown rods and control rods is indicated by two separate and independent systems, which are the Bank Demand Position Indication System (commonly called group step counters) and the Individual Rod Position Indication (IRPI) System.

The Bank Demand Position Indication System counts the pulses from the rod control system that moves the rods. There is one step counter for each group of rods. Individual rods in a group all receive the same signal to move and should, therefore, all be at the same position indicated by the group step counter for that group. The Bank Demand Position Indication System is highly precise (± 1 step or ± 5/8 inch). If a rod does not move one step for each demand pulse, the step counter will still count the pulse and incorrectly reflect the position of the rod.

The IRPI System provides an indication of actual control rod position, but at a lower precision than the step counters. This

BASES

BACKGROUND (continued)

system is based on inductive analog signals from a coil stack located above the stepping mechanisms of the control rod magnetic jacks, external to the pressure housing, but concentric with the rod travel. When the associated control rod is at the bottom of the core, the magnetic coupling between the primary and secondary coil winding of the detector is small and there is a small voltage induced in the secondary. As the control rod is raised by the magnetic jacks, the relatively high permeability of the lift rod causes an increase in magnetic coupling. Thus, an analog signal proportional to rod position is obtained. The rod position maximum uncertainty is ± 12 steps (± 7.5 inches). Misalignment limit of 12 steps precludes a rod misalignment of > 15 inches when instrument error is considered. An indicated misalignment limit of 18 steps precludes a rod misalignment of > 18.75 inches when instrument error is considered.

APPLICABLE SAFETY ANALYSES

Control rod misalignment accidents are analyzed in the safety analysis (Ref. 3). The acceptance criteria for addressing control rod inoperability or misalignment are that:

a. There be no violations of:

    1. specified acceptable fuel design limits, or

    2. Reactor Coolant System (RCS) pressure boundary integrity; and

b. The core remains subcritical after accident transients.

Two types of misalignment are distinguished. During movement of a control rod group, one rod may stop moving, while the other rods in the group continue. This condition may cause excessive power peaking. The second type of misalignment occurs if one rod fails to insert upon a reactor trip and remains stuck fully withdrawn. This condition requires an evaluation to determine that sufficient reactivity worth is held in the control rods to

BASES

APPLICABLE SAFETY ANALYSES (Continued)

meet the SDM requirement, with the maximum worth rod stuck fully withdrawn.

Two types of analysis are performed in regard to static rod misalignment. With control banks at their insertion limits, one type of analysis considers the case when any one rod is completely inserted into the core. The second type of analysis considers the case of a completely withdrawn single rod from a bank inserted to its insertion limit. Satisfying limits on departure from nucleate boiling ratio in both of these cases bounds the situation when a rod is misaligned from its group by 12 steps.

Another type of misalignment occurs if one RCCA fails to insert upon a reactor trip and remains stuck fully withdrawn. This condition is assumed in the evaluation to determine that the required SDM is met with the maximum worth RCCA also fully withdrawn.

The Required Actions in this LCO ensure that either deviations from the alignment limits will be corrected or that THERMAL POWER will be adjusted so that excessive local linear heat rates (LHRs) will not occur, and that the requirements on SDM and ejected rod worth are preserved.

Continued operation of the reactor with a misaligned control rod is allowed if the heat flux hot channel factor ($F_Q(Z)$) and the nuclear enthalpy hot channel factor ($F^N_{\Delta H}$) are verified to be within their limits in the COLR and the safety analysis is verified to remain valid. When a control rod is misaligned, the assumptions that are used to determine the rod insertion limits, AFD limits, and quadrant power tilt limits are not preserved. Therefore, the limits may not preserve the design peaking factors, and $F_Q(Z)$ and $F^N_{\Delta H}$ must be verified directly by incore mapping. Bases Section 3.2 (Power Distribution Limits) contains more complete discussions of the relation of $F_Q(Z)$ and $F^N_{\Delta H}$ to the operating limits.

BASES

APPLICABLE SAFETY ANALYSES (Continued)

Shutdown and control rod OPERABILITY and alignment are directly related to power distributions and SDM, which are initial conditions assumed in safety analyses. Therefore they satisfy Criterion 2 of 10 CFR 50.36.

LCO

The limits on shutdown or control rod alignments ensure that the assumptions in the safety analysis will remain valid. The requirements on OPERABILITY ensure that upon reactor trip, the assumed reactivity will be available and will be inserted. The OPERABILITY requirements also ensure that the RCCAs and banks maintain the correct power distribution and rod alignment.

To ensure that individual rods are properly aligned with its associated group step counter demand position, the following limits are placed on individual rod positions:

When THERMAL POWER is > 85% RTP,

1. Groups with step counter demand position ≤ 212 steps shall have all individual indicated rod positions within 12 steps of their group step counter demand position; and

2. Groups with step counter demand position > 212 steps shall have all individual indicated rod positions ≤ +17 steps and -12 steps of their group step counter demand position

When THERMAL POWER is ≤ 85% RTP, all individual indicated rod positions shall be ≤ ± 18 steps of their group step counter demand position.

These limits ensure analysis assumptions for SDM and peaking factors are met because an indicated misalignment of 12 steps precludes a rod misalignment of > 15 inches when instrument error is considered. An indicated misalignment limit of 18 steps precludes a rod misalignment of > 18.75 inches when instrument error is considered.

BASES

LCO (continued)

Failure to meet the requirements of this LCO may produce unacceptable power peaking factors and LHRs, or unacceptable SDMs, all of which may constitute initial conditions inconsistent with the safety analysis (Ref. 4).

APPLICABILITY

The requirements on RCCA OPERABILITY and alignment are applicable in MODES 1 and 2 because these are the only MODES in which neutron (or fission) power is generated, and the OPERABILITY (i.e., trippability) and alignment of rods have the potential to affect the safety of the plant. In MODES 3, 4, 5, and 6, the alignment limits do not apply because the control rods are typically bottomed and the reactor is shut down and not producing fission power. In the shutdown MODES, the OPERABILITY of the shutdown and control rods has the potential to affect the required SDM, but this effect can be compensated for by an increase in the boron concentration of the RCS. See LCO 3.1.1, "SHUTDOWN MARGIN (SDM)," for SDM in MODES 3, 4, and 5 and LCO 3.9.1, "Boron Concentration," for boron concentration requirements during refueling.

ACTIONS

A.1.1 and A.1.2

When one or more rods are untrippable, there is a possibility that the required SDM may be adversely affected. Required Actions A.1.1 and A.1.2 apply if either SR 3.1.4.2 or SR 3.1.4.3 are not met. Under these conditions, it is important to determine the SDM, and if it is less than the required value, initiate boration until the required SDM is recovered. The Completion Time of 1 hour is adequate for determining SDM and, if necessary, for initiating emergency boration and restoring SDM.

In this situation, SDM verification must include the worth of the untrippable rod, as well as a rod of maximum worth.

BASES

ACTIONS (continued)

A.2

If the untrippable rod(s) cannot be restored to OPERABLE status, the plant must be brought to a MODE or condition in which the LCO requirements are not applicable. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours.

The allowed Completion Time is reasonable, based on operating experience, for reaching MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

B.1

When a rod becomes misaligned, it can usually be moved and is still trippable. If the rod can be realigned within the Completion Time of 1 hour, local xenon redistribution during this short interval will not be significant, and operation may proceed without further restriction. If all individual indicated rod positions are ≤ ± 18 steps of their group step counter demand position, the LCO may be met by reducing reactor power ≤ 85% RTP.

An alternative to realigning a single misaligned RCCA to the group average position is to align the remainder of the group to the position of the misaligned RCCA. However, this must be done without violating the bank sequence, overlap, and insertion limits specified in LCO 3.1.5, "Shutdown Bank Insertion Limits," and LCO 3.1.6, "Control Bank Insertion Limits." The Completion Time of 1 hour gives the operator sufficient time to adjust the rod positions in an orderly manner.

B.2.1.1 and B.2.1.2

With a misaligned rod, SDM must be verified to be within limit or boration must be initiated to restore SDM to within limit.

In many cases, realigning the remainder of the group to the misaligned rod may not be desirable. For example, realigning control bank B to a rod that is misaligned 20 steps from the top of the core would require a significant power reduction, since

BASES

ACTIONS

B.2.1.1 and B.2.1.2 (continued)

control bank D must be moved fully in and control bank C must be moved in to approximately 100 to 115 steps.

Power operation may continue with one RCCA trippable but misaligned, provided that SDM is verified within 1 hour. The Completion Time of 1 hour represents the time necessary for determining the actual unit SDM and, if necessary, aligning and starting the necessary systems and components to initiate boration.

B.2.2, B.2.3, B.2.4, B.2.5, and B.2.6

For continued operation with a misaligned rod, RTP must be reduced, SDM must periodically be verified within limits, hot channel factors ($F_Q(Z)$ and $F^N_{\Delta H}$) must be verified within limits, and the safety analyses must be re-evaluated to confirm continued operation is permissible.

Reduction of power to 75% RTP ensures that local LHR increases due to a misaligned RCCA will not cause the core design criteria to be exceeded. The Completion Time of 2 hours gives the operator sufficient time to accomplish an orderly power reduction without challenging the Reactor Protection System.

When a rod is known to be misaligned, there is a potential to impact the SDM. Since the core conditions can change with time, periodic verification of SDM is required. A Frequency of 12 hours is sufficient to ensure this requirement continues to be met.

Verifying that $F_Q(Z)$ and $F^N_{\Delta H}$ are within the required limits ensures that current operation at 75% RTP with a rod misaligned is not resulting in power distributions that may invalidate safety analysis assumptions at full power. The Completion Time of 72 hours allows sufficient time to obtain flux maps of the core power distribution using the incore flux mapping system and to calculate $F_Q(Z)$ and $F^N_{\Delta H}$.

Once current conditions have been verified acceptable, time is available to perform evaluations of accident analysis to

BASES

ACTIONS

B.2.2, B.2.3, B.2.4, B.2.5, and B.2.6 (continued)

determine that core limits will not be exceeded during a Design Basis Event for the duration of operation under these conditions. A Completion Time of 5 days is sufficient time to obtain the required input data and to perform the analysis.

The analysis specified by Required Action B.2.6 must address the potential ejected rod worth, non-uniform fuel depletion, associated transient power distribution peaking factors and accidents. The following issues must also be addressed:

a. Rod cluster control assembly insertion characteristics;

b. Rod Cluster Control Assembly Misalignment;

c. Loss of reactor coolant from small ruptured pipes or from cracks in large pipes which actuates the emergency core cooling system;

d. Single rod cluster control assembly withdrawal at full power;

e. Major reactor coolant system pipe ruptures (loss of coolant accident);

f. Major Secondary system pipe rupture; and

g. Rupture of a control rod drive mechanism housing.

C.1

When Required Actions cannot be completed within their Completion Time, the unit must be brought to a MODE or Condition in which the LCO requirements are not applicable. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours, which obviates concerns about the development of undesirable xenon or power distributions. The allowed Completion Time of 6 hours is reasonable, based on operating experience, for reaching MODE 3 from full power conditions in an orderly manner and without challenging the plant systems.

BASES

ACTIONS (continued)

D.1.1 and D.1.2

More than one control rod becoming misaligned from its group average position is not expected, and has the potential to reduce SDM. Therefore, SDM must be evaluated. One hour allows the operator adequate time to determine SDM. Restoration of the required SDM, if necessary, requires increasing the RCS boron concentration to provide negative reactivity, as described in the Bases for LCO 3.1.1. The required Completion Time of 1 hour for initiating boration is reasonable, based on the time required for potential xenon redistribution, the low probability of an accident occurring, and the steps required to complete the action. This allows the operator sufficient time to align the required valves and start the boric acid pumps. Boration will continue until the required SDM is restored.

D.2

If more than one rod is found to be misaligned or becomes misaligned because of bank movement, the unit conditions fall outside of the accident analysis assumptions. Since automatic bank sequencing would continue to cause misalignment, the unit must be brought to a MODE or Condition in which the LCO requirements are not applicable. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours.

The allowed Completion Time is reasonable, based on operating experience, for reaching MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.4.1

Verification that individual rod positions are within alignment limits at a Frequency of 12 hours provides a history that allows

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.4.1 (continued)

the operator to detect a rod that is beginning to deviate from its expected position. Rod position may be verified using normal indication, direct readings using a digital voltmeter, or the plant computer. The specified Frequency takes into account other rod position information that is continuously available to the operator in the control room, so that during actual rod motion, deviations can immediately be detected. This SR is not required to be performed for a control rod until 1 hour after completion of movement of that rod. This allowance is needed because it provides time for thermal stabilization of rod position instrumentation. This allowance is acceptable because individual rod position indicators may not accurately reflect control rod position prior to thermal stabilization and there is a presumption that individual control rods will move with their group.

SR 3.1.4.2

Verifying each control rod is OPERABLE would require that each rod be tripped. However, in MODES 1 and 2, tripping each control rod would result in radial or axial power tilts, or oscillations. Exercising each individual control rod every 92 days provides increased confidence that all rods continue to be OPERABLE without exceeding the alignment limit, even if they are not regularly tripped. Moving each control rod by 10 steps in a single direction will not cause radial or axial power tilts, or oscillations, to occur. This SR requires that control rods be inserted or withdrawn by at least 10 steps which is sufficient to ensure that rod movement can be confirmed by individual rod position indicators. Administrative controls and Technical Specification limits ensure that control rod insertion limits are met. The 92 day Frequency takes into consideration other information available to the operator in the control room and SR 3.1.4.1, which is performed more frequently and adds to the determination of OPERABILITY of the rods. Between required performances of SR 3.1.4.2 (determination of control rod OPERABILITY by movement), if a control rod(s) is discovered to be

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.4.2 (continued)

immovable, but remains trippable and aligned, the control rod(s) is considered to be OPERABLE. At any time, if a control rod(s) is immovable, a determination of the trippability (OPERABILITY) of the control rod(s) must be made, and appropriate action taken.

SR 3.1.4.3

Verification of rod drop times allows the operator to determine that the maximum rod drop time permitted is consistent with the assumed rod drop time used in the safety analysis. Measuring rod drop times prior to reactor criticality, after reactor vessel head removal, ensures that the reactor internals and rod drive mechanism will not interfere with rod motion or rod drop time, and that no degradation in these systems has occurred that would adversely affect control rod motion or drop time. This testing is performed with all RCPs operating and the average moderator temperature ≥ 500°F to simulate a reactor trip under actual conditions.

This Surveillance is performed during a plant outage, due to the plant conditions needed to perform the SR and the potential for an unplanned plant transient if the Surveillance was performed with the reactor at power.

REFERENCES

1. 10 CFR 50, Appendix A.

2. 10 CFR 50.46.

3. FSAR, Chapter 14.

4. WCAP-14668, Conditional Extension of the Rod Misalignment Technical Specification for Indian Point Unit 3, October 1996 (Proprietary).

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.5 Shutdown Bank Insertion Limits

BASES

BACKGROUND

The insertion limits of the shutdown and control rods are initial assumptions in all safety analyses that assume rod insertion upon reactor trip. The insertion limits directly affect core power and fuel burnup distributions and assumptions of available ejected rod worth, SDM and initial reactivity insertion rate.

The applicable criteria for these reactivity and power distribution design requirements are GDC 10, "Reactor Design," GDC 26, "Reactivity Control System Redundancy and Protection," GDC 28, "Reactivity Limits" (Ref. 1), and 10 CFR 50.46, "Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Reactors" (Ref. 2). Limits on control rod insertion have been established, and all rod positions are monitored and controlled during power operation to ensure that the power distribution and reactivity limits defined by the design power peaking and SDM limits are preserved.

The rod cluster control assemblies (RCCAs) are divided among control banks and shutdown banks. Each bank may be further subdivided into two groups to provide for precise reactivity control. A group consists of two or more RCCAs that are electrically paralleled to step simultaneously. A bank of RCCAs may consist of two groups that are moved in a staggered fashion, but always within one step of each other. IP3 has four control banks and four shutdown banks. See LCO 3.1.4, "Rod Group Alignment Limits," for control and shutdown rod OPERABILITY and alignment requirements, and LCO 3.1.7, "Rod Position Indication," for position indication requirements.

The control banks are used for precise reactivity control of the reactor. The positions of the control banks are normally automatically controlled by the Rod Control System, but they can also be manually controlled. They are capable of adding negative reactivity very quickly (compared to borating). The control banks must be maintained above designed insertion limits and are typically near the fully withdrawn position during normal full power operations.

BASES

BACKGROUND (Continued)

Hence, they are not capable of adding a large amount of positive reactivity. Boration or dilution of the Reactor Coolant System (RCS) compensates for the reactivity changes associated with large changes in RCS temperature, power, and fuel depletion. The design calculations are performed with the assumption that the shutdown banks are withdrawn first. The shutdown banks can be fully withdrawn without the core going critical. This provides available negative reactivity in the event of boration errors. The shutdown banks are controlled manually by the control room operator. During normal unit operation, the shutdown banks are either fully withdrawn or fully inserted. The shutdown banks must be completely withdrawn from the core, prior to withdrawing any control banks during an approach to criticality. The shutdown banks are then left in this position until the reactor is shut down. They affect core power and burnup distribution, and add negative reactivity to shut down the reactor upon receipt of a reactor trip signal.

APPLICABLE SAFETY ANALYSES

On a reactor trip, all RCCAs (shutdown banks and control banks), except the most reactive RCCA, are assumed to insert into the core. The shutdown banks shall be at or above their insertion limits and available to insert the maximum amount of negative reactivity on a reactor trip signal. The control banks may be partially inserted in the core, as allowed by LCO 3.1.6, "Control Bank Insertion Limits." The shutdown bank and control bank insertion limits are established to ensure that a sufficient amount of negative reactivity is available to shut down the reactor and maintain the required SDM (see LCO 3.1.1, "SHUTDOWN MARGIN (SDM),") following a reactor trip from full power. The combination of control banks and shutdown banks (less the most reactive RCCA, which is assumed to be fully withdrawn) is sufficient to take the reactor from full power conditions at rated temperature to zero power, and to maintain the required SDM at rated no load temperature (Ref. 3). The shutdown bank

BASES

APPLICABLE SAFETY ANALYSES (Continued)

insertion limit also limits the reactivity worth of an ejected shutdown rod when at power.

The acceptance criteria for addressing shutdown and control rod bank insertion limits and inoperability or misalignment is that:

a. There be no violations of:

   1. Specified acceptable fuel design limits, or

   2. RCS pressure boundary integrity; and

b. The core remains subcritical after accident transients.

As such, the shutdown bank insertion limits affect safety analysis involving core reactivity and SDM (Ref. 3).

The shutdown bank insertion limits preserve an initial condition assumed in the safety analyses and, as such, satisfy Criterion 2 of 10 CFR 50.36.

LCO

The shutdown banks must be within their insertion limits any time the reactor is critical or approaching criticality. This ensures that a sufficient amount of negative reactivity is available to shut down the reactor and maintain the required SDM following a reactor trip.

The shutdown bank insertion limits are defined in the COLR.

APPLICABILITY

The shutdown banks must be within their insertion limits, with the reactor in MODES 1 and 2. The applicability in MODE 2 begins prior to initial control bank withdrawal, during an approach to criticality, and continues throughout MODE 2, until all control bank rods are again fully inserted by reactor trip or by shutdown. This ensures that a sufficient amount of negative reactivity is available to shut down the reactor and maintain the

BASES

APPLICABILITY (continued)

required SDM following a reactor trip. The shutdown banks do not have to be within their insertion limits in MODE 3, unless an approach to criticality is being made. In MODE 4, 5, or 6, the shutdown banks are normally fully inserted in the core and contribute to the SDM. Refer to LCO 3.1.1 for SDM requirements in MODES 3, 4, and 5. LCO 3.9.1, "Boron Concentration," ensures adequate SDM in MODE 6.

The Applicability requirements have been modified by a Note indicating the LCO requirement is suspended during SR 3.1.4.2. This SR verifies the freedom of the rods to move, and requires the shutdown bank to move below the LCO limits, which would normally violate the LCO.

ACTIONS

A.1.1, A.1.2 and A.2

When one or more shutdown banks is not within insertion limits, 2 hours is allowed to restore the shutdown banks to within the insertion limits. This is necessary because the available SDM may be significantly reduced, with one or more of the shutdown banks not within their insertion limits. Also, verification of SDM or initiation of boration within 1 hour is required, since the SDM in MODES 1 and 2 is ensured by adhering to the control and shutdown bank insertion limits (see LCO 3.1.1). If shutdown banks are not within their insertion limits, then SDM will be verified by performing a reactivity balance calculation, considering the effects listed in the BASES for SR 3.1.1.1.

The allowed Completion Time of 2 hours provides an acceptable time for evaluating and repairing minor problems without allowing the plant to remain in an unacceptable condition for an extended period of time.

B.1

If the shutdown banks cannot be restored to within their insertion limits within 2 hours, the unit must be brought to a

BASES

ACTIONS

B.1 (continued)

MODE where the LCO is not applicable. The allowed Completion Time of 6 hours is reasonable, based on operating experience, for reaching the required MODE from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.5.1

Verification that the shutdown banks are within their insertion limits prior to an approach to criticality ensures that when the reactor is critical, or being taken critical, the shutdown banks will be available to shut down the reactor, and the required SDM will be maintained following a reactor trip. This SR and Frequency ensure that the shutdown banks are withdrawn before the control banks are withdrawn during a unit startup.

Since the shutdown banks are positioned manually by the control room operator, a verification of shutdown bank position at a Frequency of 12 hours, after the reactor is taken critical, is adequate to ensure that they are within their insertion limits. Also, the 12 hour Frequency takes into account other information available in the control room for the purpose of monitoring the status of shutdown rods.

REFERENCES

1. 10 CFR 50, Appendix A.
2. 10 CFR 50.46.
3. FSAR, Chapter 14.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.6 Control Bank Insertion Limits

BASES

BACKGROUND

The insertion limits of the shutdown and control rods are initial assumptions in all safety analyses that assume rod insertion upon reactor trip. The insertion limits directly affect core power and fuel burnup distributions and assumptions of available SDM, and initial reactivity insertion rate.

The applicable criteria for these reactivity and power distribution design requirements are GDC 10, "Reactor Design," GDC 26, "Reactivity Control System Redundancy and Protection," GDC 28, "Reactivity Limits" (Ref. 1), and 10 CFR 50.46, "Acceptance Criteria for Emergency Core Cooling Systems for Light Water Nuclear Power Reactors" (Ref. 2). Limits on control rod insertion have been established, and all rod positions are monitored and controlled during power operation to ensure that the power distribution and reactivity limits defined by the design power peaking and SDM limits are preserved.

The rod cluster control assemblies (RCCAs) are divided among control banks and shutdown banks. Each bank may be further subdivided into two groups to provide for precise reactivity control. A group consists of two or more RCCAs that are electrically paralleled to step simultaneously. A bank of RCCAs may consist of two groups that are moved in a staggered fashion, but always within one step of each other. IP3 has four control banks and four shutdown banks. See LCO 3.1.4, "Rod Group Alignment Limits," for control and shutdown rod OPERABILITY and alignment requirements, and LCO 3.1.7, "Rod Position Indication," for position indication requirements.

The control bank insertion limits are specified in the COLR. The control banks are required to be at or above the insertion limit. The COLR also indicates how the control banks are moved in an overlap pattern. Overlap is the distance travelled together by two control banks. The fully withdrawn position is defined in the COLR.

BASES

BACKGROUND (continued)

The control banks are used for precise reactivity control of the reactor. The positions of the control banks are normally controlled automatically by the Rod Control System, but can also be manually controlled. They are capable of adding reactivity very quickly (compared to borating or diluting).

The power density at any point in the core must be limited, so that the fuel design criteria are maintained. Together, LCO 3.1.4, "Rod Group Alignment Limits", LCO 3.1.5, "Shutdown Bank Insertion Limits," LCO 3.1.6, "Control Bank Insertion Limits", LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)," and LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)," provide limits on control component operation and on monitored process variables, which ensure that the core operates within the fuel design criteria.

The shutdown and control bank insertion and alignment limits, AFD, and QPTR are process variables that together characterize and control the three dimensional power distribution of the reactor core. Additionally, the control bank insertion limits control the reactivity that could be added in the event of a rod ejection accident, and the shutdown and control bank insertion limits ensure the required SDM is maintained.

Operation within the subject LCO limits will prevent fuel cladding failures that would breach the primary fission product barrier and release fission products to the reactor coolant in the event of a loss of coolant accident (LOCA), loss of flow, ejected rod, or other accident requiring termination by a Reactor Protection System (RPS) trip function.

APPLICABLE SAFETY ANALYSES

The shutdown and control bank insertion limits, AFD, and QPTR LCOs are required to prevent power distributions that could result in fuel cladding failures in the event of a LOCA, loss of flow, ejected rod, or other accident requiring termination by an RTS trip function.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The acceptance criteria for addressing shutdown and control bank insertion limits and inoperability or misalignment are that:

a. There be no violations of:

   1. specified acceptable fuel design limits, or

   2. Reactor Coolant System pressure boundary integrity; and

b. The core remains subcritical after accident transients.

As such, the shutdown and control bank insertion limits affect safety analysis involving core reactivity and power distributions (Ref. 3).

The SDM requirement is ensured by limiting the control and shutdown bank insertion limits so that allowable inserted worth of the RCCAs is such that sufficient reactivity is available in the rods to shut down the reactor to hot zero power with a reactivity margin that assumes the maximum worth RCCA remains fully withdrawn upon trip (Ref. 3).

Operation at the insertion limits or AFD limits may approach the maximum allowable linear heat generation rate or peaking factor with the allowed QPTR present. Operation at the insertion limit may also indicate the maximum ejected RCCA worth could be equal to the limiting value in fuel cycles that have sufficiently high ejected RCCA worths.

The control and shutdown bank insertion limits ensure that safety analyses assumptions for SDM, ejected rod worth, and power distribution peaking factors are preserved (Ref. 3).

The insertion limits satisfy Criterion 2 of 10 CFR 50.36 because they are initial conditions assumed in the safety analysis.

BASES

LCO

The limits on control banks sequence, overlap, and physical insertion, as defined in the COLR, must be maintained because they serve the function of preserving power distribution, ensuring that the SDM is maintained, ensuring that ejected rod worth is maintained, and ensuring adequate negative reactivity insertion is available on trip. The overlap between control banks provides more uniform rates of reactivity insertion and withdrawal and is imposed to maintain acceptable power peaking during control bank motion.

APPLICABILITY

The control bank sequence, overlap, and physical insertion limits shall be maintained with the reactor in MODES 1 and 2 with $k_{eff} \geq 1.0$. These limits must be maintained, since they preserve the assumed power distribution, ejected rod worth, SDM, and reactivity rate insertion assumptions. Applicability in MODES 3, 4, and 5 is not required, since neither the power distribution nor ejected rod worth assumptions would be exceeded in these MODES.

The applicability requirements have been modified by a Note indicating the LCO requirements are suspended during the performance of SR 3.1.4.2. This SR verifies the freedom of the rods to move, and requires the control bank to move below the LCO limits, which would violate the LCO.

ACTIONS

A.1.1, A.1.2, A.2, B.1.1, B.1.2, and B.2

When the control banks are outside the acceptable insertion limits, they must be restored to within those limits. This restoration can occur in two ways:

a. Reducing power to be consistent with rod position; or

b. Moving rods to be consistent with power.

Also, verification of SDM or initiation of boration to regain SDM is required within 1 hour, since the SDM in MODES 1 and 2

BASES

ACTIONS

A.1.1, A.1.2, A.2, B.1.1, B.1.2, and B.2 (continued)

normally ensured by adhering to the control and shutdown bank insertion limits (see LCO 3.1.1, "SHUTDOWN MARGIN (SDM)") has been upset. If control banks are not within their insertion limits, then SDM will be verified by performing a reactivity balance calculation, considering the effects listed in the BASES for SR 3.1.1.1.

Similarly, if the control banks are found to be out of sequence or in the wrong overlap configuration, they must be restored to meet the limits.

Operation beyond the LCO limits is allowed for a short time period in order to take conservative action because the simultaneous occurrence of either a LOCA, loss of flow accident, ejected rod accident, or other accident during this short time period, together with an inadequate power distribution or reactivity capability, has an acceptably low probability.

The allowed Completion Time of 2 hours for restoring the banks to within the insertion, sequence, and overlaps limits provides an acceptable time for evaluating and repairing minor problems without allowing the plant to remain in an unacceptable condition for an extended period of time.

C.1

If Required Actions A.1 and A.2, or B.1 and B.2 cannot be completed within the associated Completion Times, the plant must be brought to MODE 3, where the LCO is not applicable. The allowed Completion Time of 6 hours is reasonable, based on operating experience, for reaching the required MODE from full power conditions in an orderly manner and without challenging plant systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.6.1

This Surveillance is required to ensure that the reactor does not achieve criticality with the control banks below their insertion limits.

The estimated critical position (ECP) depends upon a number of factors, one of which is xenon concentration. If the ECP was calculated for a time different from when criticality occurs, xenon concentration could change to make the ECP substantially in error. Conversely, determining the ECP immediately before criticality could be an unnecessary burden. There are a number of unit parameters requiring operator attention at that point. Verifying the ECP calculation within 4 hours prior to criticality avoids a large error from changes in xenon concentration, but allows the operator some flexibility to schedule the ECP calculation with other startup activities.

SR 3.1.6.2

Verification of the control bank insertion limits at a Frequency of 12 hours is sufficient to detect control banks that may be approaching the insertion limits since, normally, very little rod motion occurs in 12 hours.

SR 3.1.6.3

When control banks are maintained within their insertion limits as checked by SR 3.1.6.2 above, it is unlikely that their sequence and overlap will not be in accordance with requirements provided in the COLR. A Frequency of 12 hours is consistent with the insertion limit check above in SR 3.1.6.2.

BASES

REFERENCES

1. 10 CFR 50, Appendix A.
2. 10 CFR 50.46.
3. FSAR, Chapter 14.

B 3.1 REACTIVITY CONTROL SYSTEM

B 3.1.7 Rod Position Indication

BASES

BACKGROUND

According to GDC 13 (Ref. 1), instrumentation to monitor variables and systems over their operating ranges during normal operation, anticipated operational occurrences, and accident conditions must be OPERABLE. LCO 3.1.7 is required for rod cluster control assemblies (RCCAs), or rods, to ensure OPERABILITY of position indicators to determine control rod positions and thereby ensure compliance with the rod alignment and insertion limits.

The OPERABILITY, including position indication, of the shutdown and control rods is an initial assumption in all safety analyses that assume rod insertion upon reactor trip. Maximum rod misalignment is an initial assumption in the safety analysis that directly affects core power distributions and assumptions of available SDM. Rod position indication is required to assess OPERABILITY and misalignment.

Mechanical or electrical failures may cause a rod to become inoperable or to become misaligned from its group. Rod inoperability or misalignment may cause increased power peaking, due to the asymmetric reactivity distribution and a reduction in the total available rod worth for reactor shutdown. Therefore, rod alignment and OPERABILITY are related to core operation in design power peaking limits and the core design requirement of a minimum SDM.

Limits on rod alignment and OPERABILITY have been established, and all rod positions are monitored and controlled during power operation to ensure that the power distribution and reactivity limits defined by the design power peaking and SDM limits are preserved.

Rod cluster control assemblies (RCCAs), or rods, are moved out of the core (up or withdrawn) or into the core (down or inserted) by their control rod drive mechanisms. The RCCAs are divided among control banks and shutdown banks. Each bank may be further subdivided into two groups to provide for precise reactivity control.

BASES

BACKGROUND (Continued)

The axial position of shutdown rods and control rods are determined by two separate and independent systems: the Bank Demand Position Indication System (commonly called group step counters) and the Individual Rod Position Indication (IRPI) System.

The Bank Demand Position Indication System counts the pulses from the Rod Control System that move the rods. There is one step counter for each group of rods. Individual rods in a group all receive the same signal to move and should, therefore, all be at the same position indicated by the group step counter for that group. The Bank Demand Position Indication System is considered highly precise (± 1 step or ± ⅝ inch). If a rod does not move one step for each demand pulse, the step counter will still count the pulse and incorrectly reflect the position of the rod.

The IRPI System provides an accurate indication of actual control rod position, but at a lower precision than the step counters. This system is based on inductive analog signals from a coil stack located above the stepping mechanisms of the control rod magnetic jacks, external to the pressure housing, but concentric with the rod travel. When the associated control rod is at the bottom of the core, the magnetic coupling between the primary and secondary coil winding of the detector is small and there is a small voltage induced in the secondary. As the control rod is raised by the magnetic jacks, the relatively high permeability of the lift rod causes an increase in magnetic coupling. Thus, an analog signal proportional to rod position is obtained. An indicated misalignment limit of 12 steps precludes a rod misalignment of > 15 inches when instrument error is considered. An indicated misalignment limit of 18 steps precludes a rod misalignment of > 18.75 inches when instrument error is considered.

BASES

APPLICABLE SAFETY ANALYSES

Control and shutdown rod position accuracy is essential during power operation. Power peaking, ejected rod worth, or SDM limits may be violated in the event of a Design Basis Accident (Ref. 2), with control or shutdown rods operating outside their limits undetected. Therefore, the acceptance criteria for rod position indication is that rod positions must be known with sufficient accuracy in order to verify the core is operating within the group sequence, overlap, design peaking limits, ejected rod worth, and with minimum SDM (LCO 3.1.5, "Shutdown Bank Insertion Limits," and LCO 3.1.6, "Control Bank Insertion Limits"). The rod positions must also be known in order to verify the alignment limits are preserved (LCO 3.1.4, "Rod Group Alignment Limits"). Rod positions are continuously monitored to provide operators with information that ensures the plant is operating within the bounds of the accident analysis assumptions.

The rod position indicator channels satisfy Criterion 2 of 10 CFR 50.36. The control rod position indicators monitor rod position, which is an initial condition of the accident.

LCO

LCO 3.1.7 specifies that one IRPI System and one Bank Demand Position Indication System be OPERABLE for each rod. For the rod position indicators to be OPERABLE, the SR of the LCO and the following must be met:

a. The IRPI System indicates within the required number of steps of the group step counter demand position as required by LCO 3.1.4, "Rod Group Alignment Limits";

b. For the IRPI System there are no failed coils; and

c. The Bank Demand Indication System has been calibrated either in the fully inserted position or to the IRPI System.

The agreement limit between the Bank Demand Position Indication System and the IRPI System indicates that the Bank Demand

BASES

LCO (continued)

Position Indication System is adequately calibrated, and can be used for indication of the measurement of control rod bank position.

A deviation of less than the allowable limit, given in LCO 3.1.4, in position indication for a single rod, ensures high confidence that the position uncertainty of the corresponding rod group is within the assumed values used in the analysis (that specified rod group insertion limits).

These requirements ensure that rod position indication during power operation and PHYSICS TESTS is accurate, and that design assumptions are not challenged.

OPERABILITY of the position indicator channels ensures that inoperable, misaligned, or mispositioned rods can be detected. Therefore, power peaking, ejected rod worth, and SDM can be controlled within acceptable limits.

APPLICABILITY

The requirements on the IRPI and step counters are only applicable in MODES 1 and 2 (consistent with LCO 3.1.4, LCO 3.1.5, and LCO 3.1.6), because these are the only MODES in which power is generated, and the OPERABILITY and alignment of rods have the potential to affect the safety of the plant. In the shutdown MODES, the OPERABILITY of the shutdown and control banks has the potential to affect the required SDM, but this effect can be compensated for by an increase in the boron concentration of the Reactor Coolant System.

ACTIONS

The ACTIONS table is modified by a Note indicating that a separate Condition entry is allowed for each inoperable rod position indicator per group and each demand position indicator per bank. This is acceptable because the Required Actions for each Condition provide appropriate compensatory actions for each inoperable position indicator.

BASES

ACTIONS (continued)

A.1

When one IRPI channel per group fails, the position of the rod can still be determined by use of the incore movable detectors. Based on experience, normal power operation does not require excessive movement of banks. If a bank has been significantly moved, the Required Action of B.1 or B.2 below is required. Therefore, verification of RCCA position within the Completion Time of 8 hours is adequate for allowing continued full power operation, since the probability of simultaneously having a rod significantly out of position and an event sensitive to that rod position is small.

Re-verification every 24 hours thereafter is acceptable because operating experience indicates that significant drift of an individual rod during this interval is not likely and the requirement in required Action B.1 to re-verify within 8 hours if the associated control rod bank is moved significantly during this interval.

Note that an IRPI channel is not inoperable if rod position can be determined using a digital volmeter in lieu of the installed indicators.

A.2

Reduction of THERMAL POWER to ≤ 50% RTP puts the core into a condition where rod position is not significantly affecting core peaking factors (Ref. 2).

The allowed Completion Time of 8 hours is reasonable, based on operating experience, for reducing power to ≤ 50% RTP from full power conditions without challenging plant systems and allowing for rod position determination by Required Action A.1 above.

B.1 and B.2

These Required Actions clarify that when one or more rods with inoperable position indicators have been moved in excess of 24 steps in one direction, since the position was last

BASES

ACTIONS

B.1 and B.2 (continued)

determined, the Required Actions of A.1 and A.2 are still appropriate but must be initiated promptly under Required Action B.1 to begin verifying that these rods are still properly positioned, relative to their group positions.

If, within 8 hours, the rod positions have not been determined, THERMAL POWER must be reduced to ≤ 50% RTP within 8 hours to avoid undesirable power distributions that could result from continued operation at ≥ 50% RTP, if one or more rods are misaligned by more than 24 steps. The allowed Completion Time of 8 hours provides an acceptable period of time to verify the rod positions.

C.1.1 and C.1.2

With one demand position indicator per bank inoperable (i.e., bank demand position cannot be determined), the rod positions can be determined by the IRPI System. Since normal power operation does not require excessive movement of rods, verification by administrative means that the rod position indicators are OPERABLE and the most withdrawn rod and the least withdrawn rod are ≤ 12 steps apart when > 85% RTP and ≤ 18 steps apart when ≤ 85% RTP within the allowed Completion Time of once every 8 hours is adequate.

C.2

Reduction of THERMAL POWER to ≤ 50% RTP puts the core into a condition where rod position is not significantly affecting core peaking factor limits. The allowed Completion Time of 8 hours provides an acceptable period of time to verify the rod positions per Required Actions C.1.1 and C.1.2 or reduce power to ≤ 50% RTP.

D.1

If the Required Actions cannot be completed within the associated Completion Time, the plant must be brought to a MODE in which the requirement does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours. The allowed

BASES

ACTIONS

D.1 (continued)

Completion Time is reasonable, based on operating experience, for reaching the required MODE from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.7.1

Verification that the IRPI agrees with the demand position within the required number of steps ensures that the IRPI is operating correctly. Only points within the indicated ranges are required in comparison.

This surveillance is performed prior to reactor criticality after each removal of the reactor vessel head because there is a potential for unnecessary plant transients if the SR were performed with the reactor at power.

REFERENCES

1. 10 CFR 50, Appendix A.
2. FSAR, Chapter 14.
3. WCAP-14668, Conditional Extension of the Rod Misalignment Technical Specification for Indian Point Unit 3, October 1996 (Proprietary).

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.8 PHYSICS TESTS Exceptions – MODE 2

BASES

BACKGROUND

The primary purpose of the MODE 2 PHYSICS TESTS exceptions is to permit relaxations of existing LCOs to allow certain PHYSICS TESTS to be performed.

Section XI of 10 CFR 50, Appendix B (Ref. 1), requires that a test program be established to ensure that structures, systems, and components will perform satisfactorily in service. All functions necessary to ensure that the specified design conditions are not exceeded during normal operation and anticipated operational occurrences must be tested. This testing is an integral part of the design, construction, and operation of the plant. Requirements for notification of the NRC, for the purpose of conducting tests and experiments, are specified in 10 CFR 50.59 (Ref. 2).

The key objectives of a test program (Ref. 3) are to:

a. Ensure that the facility has been adequately designed;

b. Validate the analytical models used in the design and analysis;

c. Verify the assumptions used to predict unit response; and

d. Ensure that installation of equipment in the facility has been accomplished in accordance with the design.

To accomplish these objectives, testing is performed prior to initial criticality, during startup, during low power operations, during power ascension, and after each refueling. The PHYSICS TESTS requirements for reload fuel cycles ensure that the operating characteristics of the core are consistent with the design predictions and that the core can be operated as designed (Ref. 4).

BASES

BACKGROUND (continued)

PHYSICS TESTS procedures are written and approved in accordance with established formats. The procedures include all information necessary to permit a detailed execution of the testing required to ensure that the design intent is met. PHYSICS TESTS are performed in accordance with these procedures and test results are approved prior to continued power escalation and long term power operation.

The PHYSICS TESTS required for reload fuel cycles are listed in Reference. 4.

These and other supplementary tests may be required to calibrate the nuclear instrumentation or to diagnose operational problems. These tests may cause the operating controls and process variables to deviate from their LCO requirements during their performance.

APPLICABLE SAFETY ANALYSES

The fuel is protected by LCOs that preserve the initial conditions of the core assumed during the safety analyses. The methods for development of the LCOs that are excepted by this LCO are described in the Westinghouse Reload Safety Evaluation Methodology Report (Ref. 5). These PHYSICS TESTS, and other tests that may be required to calibrate nuclear instrumentation or to diagnose operational problems, may require the operating control or process variables to deviate from their LCO limitations.

The FSAR defines requirements for initial testing of the facility, including PHYSICS TESTS. Requirements for reload fuel cycle PHYSICS TESTS are defined in ANSI/ANS-19.6.1-1985 (Ref. 4). Although these PHYSICS TESTS are generally accomplished within the limits for all LCOs, conditions may occur when one or more LCOs must be suspended to make completion of PHYSICS TESTS possible or practical. This is acceptable as long as the fuel design criteria are not violated. When one or more of the requirements specified in LCO 3.1.3, "Moderator Temperature

BASES

APPLICABLE SAFETY ANALYSES (continued)

"Coefficient (MTC)," LCO 3.1.4, "Group Rod Alignments", LCO 3.1.5, "Shutdown Bank Insertion Limits", LCO 3.1.6, "Control Bank Insertion Limits", and LCO 3.4.2, "RCS Minimum Temperature for Criticality", are suspended for PHYSICS TESTS, the fuel design criteria are preserved as long as the power level is limited to ≤ 5% RTP, the reactor coolant temperature is kept ≥ 540°F, and SDM is kept within the limits specified in the COLR for low power physics tests.

The PHYSICS TESTS include measurement of core nuclear parameters or the exercise of control components that affect process variables. Among the process variables involved are AFD and QPTR, which represent initial conditions of the unit safety analyses. Also involved are Rod Cluster Control Assemblies (RCCAs) or control rods (control and shutdown rods), which are required to shut down the reactor. The limits for these variables are specified for each fuel cycle in the COLR. PHYSICS TESTS meet the criteria for inclusion in the Technical Specifications, since the components and process variable LCOs suspended during PHYSICS TESTS meet Criteria 1, 2, and 3 of 10 CFR 50.36.

Reference 6 allows special test exceptions (STEs) to be included as part of the LCO that they affect. It was decided, however, to retain this STE as a separate LCO because it was less cumbersome and provided additional clarity.

LCO

This LCO allows the reactor MTC to be outside its specified limits. In addition, it allows selected control and shutdown rods to be positioned outside of their specified alignment and insertion limits. Operation beyond specified limits is permitted for the purpose of performing PHYSICS TESTS and poses no threat to fuel integrity, provided the SRs are met.

The requirements of LCO 3.1.3, LCO 3.1.4, LCO 3.1.5, LCO 3.1.6, and LCO 3.4.2 may be suspended during the performance of PHYSICS TESTS provided:

a. RCS lowest loop average temperature is ≥ 540 °F;

BASES

LCO (continued)

b. SDM is within the limit specified in the COLR; and

c. THERMAL POWER is ≤ 5% RTP.

APPLICABILITY

This LCO is applicable in MODE 2 when performing low power PHYSICS TESTS. The applicable PHYSICS TESTS are performed in MODE 2 at HZP.

ACTIONS

A.1 and A.2

If the SDM requirement is not met, boration must be initiated promptly. A Completion Time of 15 minutes is adequate for an operator to correctly align and start the required systems and components. The operator should begin boration with the best source available for the plant conditions. Boration will be continued until SDM is within limit.

Suspension of PHYSICS TESTS exceptions requires restoration of each of the applicable LCOs to within specification.

B.1

When THERMAL POWER is > 5% RTP, as indicated on power range instruments, the only acceptable action is to open the reactor trip breakers (RTBs) to prevent operation of the reactor beyond its design limits. Immediately opening the RTBs will shut down the reactor and prevent operation of the reactor outside of its design limits.

C.1

When the RCS lowest T_{avg} is < 540°F, the appropriate action is to restore T_{avg} to within its specified limit. The allowed Completion Time of 15 minutes provides time for restoring T_{avg} to within limits without allowing the plant to remain in an unacceptable condition for an extended period of time. Operation

BASES

ACTIONS

C.1 (continued)

with the reactor critical and with temperature below 540°F could violate the assumptions for accidents analyzed in the safety analyses.

D.1

If the Required Actions cannot be completed within the associated Completion Time, the plant must be brought to a MODE in which the requirement does not apply. To achieve this status, the plant must be brought to at least MODE 3 within an additional 15 minutes. The Completion Time of 15 additional minutes is reasonable, based on operating experience, for reaching MODE 3 in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.8.1

The power range and intermediate range neutron detectors must be verified to be OPERABLE in MODE 2 by LCO 3.3.1, "Reactor Protection System (RPS) Instrumentation." The frequency is specified in LCO 3.3.1. A CHANNEL OPERATIONAL TEST is normally performed on each power range and intermediate range channel prior to initiation of the PHYSICS TESTS. This will ensure that the RPS is properly aligned to provide the required degree of core protection during the performance of the PHYSICS TESTS.

SR 3.1.8.2

Verification that the RCS lowest loop T_{avg} is $\geq$ 540°F will ensure that the unit is not operating in a condition that could invalidate the safety analyses. Verification of the RCS temperature at a Frequency of 30 minutes during the performance of the PHYSICS TESTS will ensure that the initial conditions of the safety analyses are not violated.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.1.8.3

Verification that THERMAL POWER is ≤ 5% RTP will ensure that the plant is not operating in a condition that could invalidate the safety analysis. Verification of THERMAL POWER at a Frequency of 30 minutes during the performance of the PHYSICS TESTS will ensure that the initial conditions of the safety analyses are not violated.

SR 3.1.8.4

The SDM is verified by performing a reactivity balance calculation, considering the following reactivity effects:

a. RCS boron concentration;

b. Control bank position;

c. RCS average temperature;

d. Fuel burnup based on gross thermal energy generation;

e. Xenon concentration;

f. Samarium concentration; and

g. Isothermal temperature coefficient (ITC).

Using the ITC accounts for Doppler reactivity in this calculation when the reactor is subcritical, and the fuel temperature will be changing at the same rate as the RCS.

The Frequency of 24 hours is based on the generally slow change in required boron concentration and on the low probability of an accident occurring without the required SDM.

BASES

REFERENCES

1. 10 CFR 50, Appendix B, Section XI.

2. 10 CFR 50.59.

3. Regulatory Guide 1.68, Revision 2, August, 1978.

4. ANSI/ANS-19.6.1-1985, December 13, 1985.

5. WCAP-9273-NP-A, "Westinghouse Reload Safety Evaluation Methodology Report," July 1985.

6. WCAP-11618, including Addendum 1, April 1989.

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.1 Heat Flux Hot Channel Factor ($F_Q(Z)$)

BASES

BACKGROUND

The purpose of the limits on the values of $F_Q(Z)$ is to limit the local (i.e., pellet) peak power density. The value of $F_Q(Z)$ varies along the axial height (Z) of the core.

$F_Q(Z)$ is defined as the maximum local fuel rod linear power density divided by the average fuel rod linear power density, assuming nominal fuel pellet and fuel rod dimensions. Therefore, $F_Q(Z)$ is a measure of the peak fuel pellet power within the reactor core.

During power operation, the global power distribution is limited by LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)," and LCO 3.2.4, "QUADRANT TILT POWER RATIO (QPTR)," which are directly and continuously measured process variables. These LCOs, along with LCO 3.1.6, "Control Bank Insertion Limits," maintain the core limits on power distributions on a continuous basis.

$F_Q(Z)$ varies with fuel loading patterns, control bank insertion, fuel burnup, and changes in axial power distribution.

$F_Q(Z)$ is measured periodically using the incore detector system. These measurements are generally taken with the core at or near steady state conditions.

Using the measured three dimensional power distributions, it is possible to derive a measured value for $F_Q(Z)$. However, because this value represents a steady state condition, it does not include the variations in the value of $F_Q(Z)$ that are present during nonequilibrium situations.

Core monitoring and control under nonsteady state conditions are accomplished by operating the core within the limits of the appropriate LCOs, including the limits on AFD, QPTR, and control rod insertion.

BASES

APPLICABLE SAFETY ANALYSES

This LCO precludes core power distributions that violate the following fuel design criteria:

a. During a large break loss of coolant accident (LOCA), the peak cladding temperature must not exceed 2200°F (Ref. 1);

b. During a loss of forced reactor coolant flow accident, there must be at least 95% probability at the 95% confidence level (the 95/95 DNB criterion) that the hot fuel rod in the core does not experience a departure from nucleate boiling (DNB) condition;

c. During an ejected rod accident, the energy deposition to the fuel must not exceed 225 calories/gram for non-irradiated fuel and 200 calories/gram for irradiated fuel (Ref. 2); and

d. The control rods must be capable of shutting down the reactor with a minimum required SDM with the highest worth control rod stuck fully withdrawn (Ref. 3).

Limits on $F_Q(Z)$ ensure that the value of the initial total peaking factor assumed in the accident analyses remains valid. Other criteria must also be met (e.g., maximum cladding oxidation, maximum hydrogen generation, coolable geometry, and long term cooling). However, the peak cladding temperature is typically most limiting.

$F_Q(Z)$ limits assumed in the LOCA analysis are typically limiting relative to (i.e., lower than) the $F_Q(Z)$ limit assumed in safety analyses for other postulated accidents. Therefore, this LCO provides conservative limits for other postulated accidents.

$F_Q(Z)$ satisfies Criterion 2 of 10 CFR 50.36.

LCO

The Heat Flux Hot Channel Factor, $F_Q(Z)$, shall be limited by the following relationships:

BASES

LCO (continued)

$$F_Q(Z) \le \frac{FQ}{P} K(Z) \qquad \text{for } P > 0.5$$

$$F_Q(Z) \le \frac{FQ}{0.5} K(Z) \qquad \text{for } P \le 0.5$$

where: FQ is the $F_Q(Z)$ limit at RTP provided in the COLR,

K(Z) is the normalized $F_Q(Z)$ as a function of core height provided in the COLR, and

$$P = \frac{\text{THERMAL POWER}}{\text{RTP}}$$

The current IP3 specific values of FQ and K(Z) are given in the COLR.

An $F_Q(Z)$ evaluation requires obtaining an incore flux map in MODE 1. From the incore flux map results we obtain the measured value ($F_Q^M(Z)$) of $F_Q(Z)$. Then,

$$F_Q(Z) = F_Q^M(Z)\ 1.0815$$

where 1.0815 is a factor that accounts for fuel manufacturing tolerances and flux map measurement uncertainty. This correction factor for the measured value of total peaking factor $F_Q^M(Z)$ is for the three percent needed to account for manufacturing tolerances and this value is further increased by five percent to account for measurement error.

The $F_Q(Z)$ limits define limiting values for core power peaking that precludes peak cladding temperatures exceeding 2200°F during either a large or small break LOCA.

This LCO requires operation within the bounds assumed in the safety analyses. Calculations are performed in the core design process to confirm that the core can be controlled in such a manner during operation that it can stay within the LOCA $F_Q(Z)$

BASES

LCO (continued)

limits. If $F_Q(Z)$ cannot be maintained within the LCO limits, reduction of the core power is required.

Violating the LCO limits for $F_Q(Z)$ produces unacceptable consequences if a design basis event occurs while $F_Q(Z)$ is outside its specified limits.

APPLICABILITY

The $F_Q(Z)$ limits must be maintained in MODE 1 to prevent core power distributions from exceeding the limits assumed in the safety analyses. Applicability in other MODES is not required because there is either insufficient stored energy in the fuel or insufficient energy being transferred to the reactor coolant to require a limit on the distribution of core power.

ACTIONS

A.1

Reducing THERMAL POWER by ≥ 1% RTP for each 1% by which $F_Q(Z)$ exceeds its limit, maintains an acceptable absolute power density. The Completion Time of 15 minutes provides an acceptable time to reduce power in an orderly manner and without allowing the plant to remain in an unacceptable condition for an extended period of time.

A.2

A reduction of the Power Range Neutron Flux–High trip setpoints by ≥ 1% for each 1% by which $F_Q(Z)$ exceeds its limit, is a conservative action for protection against the consequences of severe transients with unanalyzed power distributions. The Completion Time of 72 hours is sufficient considering the small likelihood of a severe transient in this time period and the preceding prompt reduction in THERMAL POWER in accordance with Required Action A.1.

BASES

ACTIONS (continued)

A.3

Verification that $F_Q(Z)$ has been restored to within its limit, by performing SR 3.2.1.1 prior to increasing THERMAL POWER above the limit imposed by Required Action A.1, ensures that core conditions during operation at higher power levels are consistent with safety analyses assumptions.

B.1

If Required Actions A.1 through A.3 are not met within their associated Completion Times, the plant must be placed in a mode or condition in which the LCO requirements are not applicable. This is done by placing the plant in at least MODE 2 within 6 hours.

This allowed Completion Time is reasonable based on operating experience regarding the amount of time it takes to reach MODE 2 from full power operation in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.2.1.1 is modified by a Note. The Note applies during the first power ascension after a refueling. It states that THERMAL POWER may be increased until an equilibrium power level has been achieved at which a power distribution map can be obtained. This allowance is modified, however, by one of the Frequency conditions that requires verification that $F_Q(Z)$ is within specified limits after a power rise of more than 10% RTP over the THERMAL POWER at which it was last verified to be within specified limits. Because $F_Q(Z)$ could not have previously been measured in this reload core, there is a second Frequency condition, applicable only for reload cores, that requires determination of these parameters before exceeding 75% RTP. This ensures that some determination of $F_Q(Z)$ is made at a lower power level at which adequate margin is available before going to 100% RTP. Also, this Frequency condition, together with the

BASES

SURVEILLANCE REQUIREMENTS (continued)

Frequency condition requiring verification of $F_Q(Z)$ following a power increase of more than 10%, ensures that it was verified as soon as RTP (or any other level for extended operation) is achieved. In the absence of these Frequency conditions, it is possible to increase power to RTP and operate for 31 days without verification of $F_Q(Z)$. The Frequency condition is not intended to require verification of these parameters after every 10% increase in power level above the last verification. It only requires verification after a power level is achieved for extended operation that is 10% higher than that power at which F_Q was last measured.

SR 3.2.1.1

Verification that $F_Q(Z)$ is within its specified limits involves increasing $F_Q^M(Z)$ to allow for manufacturing tolerance and measurement uncertainties in order to obtain $F_Q(Z)$. Specifically, $F_Q^M(Z)$ is the measured value of $F_Q(Z)$ obtained from incore flux map results and $F_Q(Z) = F_Q^M(Z)\ 1.0815$ (Ref. 4). $F_Q(Z)$ is then compared to its specified limits.

The limit with which $F_Q(Z)$ is compared varies inversely with power above 50% RTP and directly with a function called K(Z) provided in the COLR.

Performing this Surveillance in MODE 1 prior to exceeding 75% RTP ensures that the $F_Q(Z)$ limit is met when RTP is achieved, because the highest peaking factors (i.e., the ratio of local power density to the core average power density) generally decrease as core average power level is increased.

If THERMAL POWER has been increased by $\geq$ 10% RTP since the last determination of $F_Q(Z)$, another evaluation of this factor is required 12 hours after achieving equilibrium conditions at this higher power level (to ensure that $F_Q(Z)$ values are being reduced sufficiently with power increase to stay within the LCO limits).

The Frequency of 31 EFPD is adequate to monitor the change of power distribution with core burnup because such changes are slow

BASES

SURVEILLANCE REQUIREMENTS

SR 3.2.1.1 (continued)

and well controlled when the plant is operated in accordance with the Technical Specifications (TS).

REFERENCES

1. 10 CFR 50.46, 1974.
2. FSAR 14.2.6.
3. 10 CFR 50, Appendix A.
4. WCAP-7308-L-P-A, "Evaluation of Nuclear Hot Channel Factor Uncertainties".

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.2 Nuclear Enthalpy Rise Hot Channel Factor ($F^N_{\Delta H}$)

BASES

BACKGROUND

The purpose of this LCO is to establish limits on the power density at any point in the core so that the fuel design criteria are not exceeded and the accident analysis assumptions remain valid. The design limits on local (pellet) and integrated fuel rod peak power density are expressed in terms of hot channel factors. Control of the core power distribution with respect to these factors ensures that local conditions in the fuel rods and coolant channels do not challenge core integrity at any location during either normal operation or a postulated accident analyzed in the safety analyses.

$F^N_{\Delta H}$ is defined as the ratio of the integral of the linear power along the fuel rod with the highest integrated power to the average integrated fuel rod power. Therefore, $F^N_{\Delta H}$ is a measure of the maximum total power produced in a fuel rod.

$F^N_{\Delta H}$ is sensitive to fuel loading patterns, bank insertion, and fuel burnup. $F^N_{\Delta H}$ typically increases with control bank insertion and typically decreases with fuel burnup.

$F^N_{\Delta H}$ is not directly measurable but is inferred from a power distribution map obtained with the movable incore detector system. Specifically, the results of the three dimensional power distribution map are analyzed by a computer to determine $F^N_{\Delta H}$. This factor is calculated at least every 31 EFPD. However, during power operation, the global power distribution is monitored by LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)," and LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)," which address directly and continuously measured process variables.

The COLR provides peaking factor limits that ensure that the design basis value of the departure from nucleate boiling (DNB) is met for normal operation, operational transients, and any transient condition arising from events of moderate frequency. The DNB design basis precludes DNB and is met by limiting the minimum local DNB heat flux ratio to 1.3 using the W3 CHF correlation. All DNB limited transient events are assumed to

BASES

BACKGROUND (Continued)

begin with an $F^N_{\Delta H}$ value that satisfies the LCO requirements. Operation outside the LCO limits may produce unacceptable consequences if a DNB limiting event occurs. The DNB design basis ensures that there is no overheating of the fuel that results in possible cladding perforation with the release of fission products to the reactor coolant.

APPLICABLE SAFETY ANALYSES

Limits on $F^N_{\Delta H}$ preclude core power distributions that exceed the following fuel design limits:

a. There must be at least 95% probability at the 95% confidence level (the 95/95 DNB criterion) that the hottest fuel rod in the core does not experience a DNB condition;

b. During a large break loss of coolant accident (LOCA), peak cladding temperature (PCT) must not exceed 2200°F;

c. During an ejected rod accident, the energy deposition to the fuel must not exceed 225 calories/gram for non-irradiated fuel and 200 calories/gram for irradiated fuel (Ref. 1); and

d. Fuel design limits required by GDC 26 (Ref. 2) for the condition when control rods must be capable of shutting down the reactor with a minimum required SDM with the highest worth control rod stuck fully withdrawn.

For transients that may be DNB limited, the Reactor Coolant System flow and $F^N_{\Delta H}$ are the core parameters of most importance. The limits on $F^N_{\Delta H}$ ensure that the DNB design basis is met for normal operation, operational transients, and any transients arising from events of moderate frequency. The DNB design basis is met by limiting the minimum DNBR to the 95/95 DNB criterion of 1.3 using the W3 CHF correlation. This value provides a high degree of assurance that the hottest fuel rod in the core does not experience a DNB.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The allowable $F^N_{\Delta H}$ limit increases with decreasing power level. This functionality in $F^N_{\Delta H}$ is included in the analyses that provide the Reactor Core Safety Limits (SLs) of SL 2.1.1. Therefore, any DNB events in which the calculation of the core limits is modeled implicitly use this variable value of $F^N_{\Delta H}$ in the analyses. Likewise, all transients that may be DNB limited are assumed to begin with an initial $F^N_{\Delta H}$ as a function of power level defined by the COLR limit equation.

The LOCA safety analysis indirectly models $F^N_{\Delta H}$ as an input parameter. The Nuclear Heat Flux Hot Channel Factor ($F_Q(Z)$) and the axial peaking factors are inserted directly into the LOCA safety analyses that verify the acceptability of the resulting peak cladding temperature (Ref. 3).

The fuel is protected in part by Technical Specifications, which ensure that the initial conditions assumed in the safety and accident analyses remain valid. The following LCOs ensure this: LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)," LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)," LCO 3.1.6, "Control Bank Insertion Limits," LCO 3.2.2, "Nuclear Enthalpy Rise Hot Channel Factor ($F^N_{\Delta H}$)," and LCO 3.2.1, "Heat Flux Hot Channel Factor ($F_Q(Z)$)."

$F^N_{\Delta H}$ and $F_Q(Z)$ are measured periodically using the movable incore detector system. Measurements are generally taken with the core at, or near, steady state conditions. Core monitoring and control under transient conditions (Condition 1 events) are accomplished by operating the core within the limits of the LCOs on AFD, QPTR, and Bank Insertion Limits.

$F^N_{\Delta H}$ satisfies Criterion 2 of 10 CFR 50.36.

LCO

$F^N_{\Delta H}$ shall be maintained within the limits of the relationship provided in the COLR.

The $F^N_{\Delta H}$ limit identifies the coolant flow channel with the maximum enthalpy rise. This channel has the least additional

BASES

LCO (continued)

heat removal capability and thus the highest probability for a DNB.

The limiting value of $F^N_{\Delta H}$, described by the equation contained in the COLR, is the design radial peaking factor used in the unit safety analyses.

A power multiplication factor in this equation includes an additional margin for higher radial peaking from reduced thermal feedback and greater control rod insertion at low power levels. The limiting value of $F^N_{\Delta H}$ is allowed to increase a small amount for every 1% RTP reduction in THERMAL POWER as specified in the COLR.

APPLICABILITY

The $F^N_{\Delta H}$ limits must be maintained in MODE 1 to preclude core power distributions from exceeding the fuel design limits for DNBR and PCT. Applicability in other modes is not required because there is either insufficient stored energy in the fuel or insufficient energy being transferred to the coolant to require a limit on the distribution of core power. Specifically, the design bases events that are sensitive to $F^N_{\Delta H}$ in other modes (MODES 2 through 5) have significant margin to DNB, and therefore, there is no need to restrict $F^N_{\Delta H}$ in these modes.

ACTIONS

A.1.1

With $F^N_{\Delta H}$ exceeding its limit, the unit is allowed 4 hours to restore $F^N_{\Delta H}$ to within its limits. This restoration may, for example, involve realigning any misaligned rods or reducing power enough to bring $F^N_{\Delta H}$ within its power dependent limit. When the $F^N_{\Delta H}$ limit is exceeded, the DNBR limit is not likely violated in steady state operation, because events that could significantly perturb the $F^N_{\Delta H}$ value (e.g., static control rod misalignment) are considered in the safety analyses. However, the DNBR limit may be violated if a DNB limiting event occurs. Thus, the allowed Completion Time of 4 hours provides an acceptable time to restore

BASES

ACTIONS

A.1.1 (continued)

$F^N_{\Delta H}$ to within its limits without allowing the plant to remain in an unacceptable condition for an extended period of time.

Condition A is modified by a Note that requires that Required Actions A.2 and A.3 must be completed whenever Condition A is entered. Thus, if power is not reduced because this Required Action is completed within the 4 hour time period, Required Action A.2 nevertheless requires another measurement and calculation of $F^N_{\Delta H}$ within 24 hours in accordance with SR 3.2.2.1.

However, if power is reduced below 50% RTP, Required Action A.3 requires that another determination of $F^N_{\Delta H}$ must be done prior to exceeding 50% RTP, prior to exceeding 75% RTP, and within 24 hours after reaching or exceeding 95% RTP. In addition, Required Action A.2 is performed if power ascension is delayed past 24 hours.

A.1.2.1 and A.1.2.2

If the value of $F^N_{\Delta H}$ is not restored to within its specified limit either by adjusting a misaligned rod or by reducing THERMAL POWER, the alternative option is to reduce THERMAL POWER to < 50% RTP in accordance with Required Action A.1.2.1 and reduce the Power Range Neutron Flux – High to ≤ 55% RTP in accordance with Required Action A.1.2.2. Reducing THERMAL POWER to < 50% RTP increases the DNB margin and does not likely cause the DNBR limit to be violated in steady state operation. The reduction in trip setpoints ensures that continuing operation remains at an acceptable low power level with adequate DNBR margin. The allowed Completion Time of 4 hours for Required Action A.1.2.1 is consistent with those allowed for in Required Action A.1.1 and provides an acceptable time to reach the required power level from full power operation without allowing the plant to remain in an unacceptable condition for an extended period of time. The Completion Times of 4 hours for Required Actions A.1.1 and A.1.2.1 are not additive.

The allowed Completion Time of 72 hours to reset the trip setpoints per Required Action A.1.2.2 recognizes that, once power is reduced, the safety analysis assumptions are satisfied and

BASES

ACTIONS

A.1.2.1 and A.1.2.2 (continued)

there is no urgent need to reduce the trip setpoints. This is a sensitive operation that may inadvertently trip the Reactor Protection System.

A.2

Once the power level has been reduced to < 50% RTP per Required Action A.1.2.1, an incore flux map (SR 3.2.2.1) must be obtained and the measured value of $F^N_{\Delta H}$ verified not to exceed the allowed limit at the lower power level. The unit is provided 20 additional hours to perform this task over and above the 4 hours allowed by either Action A.1.1 or Action A.1.2.1. The Completion Time of 24 hours is acceptable because of the increase in the DNB margin, which is obtained at lower power levels, and the low probability of having a DNB limiting event within this 24 hour period. Additionally, operating experience has indicated that this Completion Time is sufficient to obtain the incore flux map, perform the required calculations, and evaluate $F^N_{\Delta H}$.

A.3

Verification that $F^N_{\Delta H}$ is within its specified limits after an out of limit occurrence ensures that the cause that led to the $F^N_{\Delta H}$ exceeding its limit is corrected, and that subsequent operation proceeds within the LCO limit. This Action demonstrates that the $F^N_{\Delta H}$ limit is within the LCO limits prior to exceeding 50% RTP, again prior to exceeding 75% RTP, and within 24 hours after THERMAL POWER is ≥ 95% RTP.

This Required Action is modified by a Note that states that THERMAL POWER does not have to be reduced prior to performing this Action.

B.1

When Required Actions A.1.1 through A.3 cannot be completed within their required Completion Times, the plant must be placed in a mode in which the LCO requirements are not applicable. This is done by placing the plant in at least MODE 2 within 6 hours. The allowed Completion Time of 6 hours is reasonable, based on

BASES

ACTIONS

B.1 (continued)

operating experience regarding the time required to reach MODE 2 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.2.2.1

The value of $F^N_{\Delta H}$ is determined by using the movable incore detector system to obtain a flux distribution map. A data reduction computer program then calculates the maximum value of $F^N_{\Delta H}$ from the measured flux distributions. The measured value of $F^N_{\Delta H}$ must be multiplied by 1.04 to account for measurement uncertainty before making comparisons to the $F^N_{\Delta H}$ limit.

After each refueling, $F^N_{\Delta H}$ must be determined in MODE 1 prior to exceeding 75% RTP. This requirement ensures that $F^N_{\Delta H}$ limits are met at the beginning of each fuel cycle.

The 31 EFPD Frequency is acceptable because the power distribution changes relatively slowly over this amount of fuel burnup. Accordingly, this Frequency is short enough that the $F^N_{\Delta H}$ limit cannot be exceeded for any significant period of operation.

REFERENCES

1. FSAR 14.2.6.
2. 10 CFR 50, Appendix A.
3. 10 CFR 50.46.

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.3 AXIAL FLUX DIFFERENCE (AFD) (Constant Axial Offset Control (CAOC) Methodology)

BASES

BACKGROUND

The purpose of this LCO is to establish limits on the values of the AFD in order to limit the axial power distribution skewing to either the top or bottom of the core. By limiting the amount of power distribution skewing, core peaking factors are consistent with the assumptions used in the safety analyses. Limiting power distribution skewing over time also minimizes the xenon distribution skewing, which is a significant factor in axial power distribution control.

The operating scheme used to control the axial power distribution, CAOC, involves maintaining the AFD within a tolerance band around a burnup dependent target, known as the target flux difference, to minimize the variation of the axial peaking factor and axial xenon distribution during unit maneuvers.

The target flux difference is determined at equilibrium xenon conditions. The control banks must be positioned within the core in accordance with their insertion limits and Control Bank D should be inserted near its normal position (i.e., $\geq$ 190 steps withdrawn) for steady state operation at high power levels. The power level should be as near RTP as practical. The value of the target flux difference obtained under these conditions divided by the Fraction of RTP is the target flux difference at RTP for the associated core burnup conditions. Target flux differences for other THERMAL POWER levels are obtained by multiplying the RTP value by the appropriate fractional THERMAL POWER level.

Periodic updating of the target flux difference value is necessary to follow the change of the flux difference at steady state conditions with burnup.

The Nuclear Enthalpy Rise Hot Channel Factor ($F^N_{\Delta H}$) and QPTR LCOs limit the radial component of the peaking factors.

BASES

BACKGROUND (continued)

The shape of the power profile in the axial (i.e., the vertical) direction is largely under the control of the operator, through either the manual operation of the control banks, or automatic motion of control banks responding to temperature deviations resulting from either manual operation of the Chemical and Volume Control System to change boron concentration, or from power level changes.

APPLICABLE SAFETY ANALYSES

The AFD is a measure of axial power distribution skewing to the top or bottom half of the core. The AFD is sensitive to many core related parameters such as control bank positions, core power level, axial burnup, axial xenon distribution and, to a lesser extent, reactor coolant temperature and boron concentrations. The allowed range of the AFD is used in the nuclear design process to confirm that operation within these limits produces core peaking factors and axial power distributions that meet safety analysis requirements.

The CAOC methodology entails:

a. Establishing an envelope of allowed power shapes and power densities;

b. Devising an operating strategy for the cycle that maximizes unit flexibility (maneuvering) and minimizes axial power shape changes;

c. Demonstrating that this strategy does not result in core conditions that violate the envelope of permissible core power characteristics; and

d. Demonstrating that this power distribution control scheme can be effectively supervised with excore detectors.

The limits on the AFD ensure that the Heat Flux Hot Channel Factor ($F_Q(Z)$) is not exceeded during either normal operation or in the event of xenon redistribution following power changes.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The limits on the AFD also limit the range of power distributions that are assumed as initial conditions in analyzing Condition 2, 3, and 4 events. This ensures that fuel cladding integrity is maintained for these postulated accidents. The most important Condition 4 event is the loss of coolant accident. The most significant Condition 3 event is the loss of flow accident. The most significant Condition 2 events are uncontrolled bank withdrawal and boration or dilution accidents. Condition 2 accidents, assumed to begin from within the AFD limits, are used to confirm the adequacy of Overpower ΔT and Overtemperature ΔT trip setpoints.

The limits on the AFD satisfy Criterion 2 of 10 CFR 50.36.

LCO

Signals are available to the operator from the Nuclear Instrumentation System (NIS) excore neutron detectors (Ref. 1). Separate signals are taken from the top and bottom detectors. The AFD is defined as the difference in normalized flux signals between the top and bottom excore detector in each detector well. For convenience, this flux difference is converted to provide flux difference units expressed as a percentage and labeled as %Δ flux or %ΔI.

The AFD LCO establishes the limits for how much and for how long the measured AFD may deviate from a predetermined (i.e., target) AFD. The amount that the measured AFD may deviate from the target AFD is called the "target band" which is specified in the COLR. If the measured AFD is within the "target band," then there are no restrictions on plant operations.

If the measured AFD cannot be consistently maintained within the "target band" but can be maintained within the "acceptable operation limits," then reactor power must be reduced to < 90% RTP. However, even with power reduced, the measured AFD must be maintained within the target band for 23 out of every 24 hours (i.e., the cumulative penalty deviation time cannot be exceeded); otherwise additional power reductions are required.

BASES

LCO (continued)

If the measured axial flux difference cannot be maintained within the "acceptable operation limits" or the cumulative penalty deviation time for operating outside the target band is exceeded, then reactor power must be reduced to < 50% RTP. There are no restrictions on measured AFD when reactor power is < 50% RTP; however, the measured AFD must be within the "target band" for a specified period of time (i.e., the cumulative penalty deviation time must be within a specified limit) before reactor power can be increased ≥ 50% RTP.

The required target band varies with axial burnup distribution, which in turn varies with the core average accumulated burnup. The target band defined in the COLR may provide one target band for the entire cycle or more than one band, each to be followed for a specific range of cycle burnup.

With THERMAL POWER ≥ 90% RTP, the AFD must be kept within the target band. With the AFD outside the target band with THERMAL POWER ≥ 90% RTP, the assumptions of the accident analyses may be violated.

The frequency of monitoring the AFD by the unit computer is once per minute providing an essentially continuous accumulation of penalty deviation time that allows the operator to accurately assess the status of the penalty deviation time.

Violating the LCO on the AFD could produce unacceptable consequences if a Condition 2, 3, or 4 event occurs while the AFD is outside its limits.

Target band and AFD acceptable operation limits are specified in the COLR.

The LCO is modified by four Notes. Note 1 states the conditions necessary for declaring the AFD outside of the target band. Notes 2 and 3 describe how the cumulative penalty deviation time is calculated. It is intended that the unit is operated with the AFD within the target band about the target flux difference. However, during rapid THERMAL POWER reductions, control bank motion may cause the AFD to deviate outside of the target band at reduced THERMAL POWER levels. This deviation does not affect the

BASES

LCO (continued)

xenon distribution sufficiently to change the envelope of peaking factors that may be reached on a subsequent return to RTP with the AFD within the target band, provided the time duration of the deviation is limited. Accordingly, while THERMAL POWER is ≥ 50% RTP and < 90% RTP (i.e., Part b of this LCO), a 1 hour cumulative penalty deviation time limit, cumulative during the preceding 24 hours, is allowed during which the unit may be operated outside of the target band but within the acceptable operation limits provided in the COLR. This penalty time is accumulated at the rate of 1 minute for each 1 minute of operating time within the power range of Part b of this LCO (i.e., THERMAL POWER 50% RTP). The cumulative penalty time is the sum of penalty times from Parts b and c of this LCO.

For THERMAL POWER levels > 15% RTP and < 50% RTP (i.e., Part c of this LCO), deviations of the AFD outside of the target band are less significant. Note 3 allows the accumulation of 1/2 minute penalty deviation time per 1 minute of actual time outside the target band and reflects this reduced significance. With THERMAL POWER < 15% RTP, AFD is not a significant parameter in the assumptions used in the safety analysis and, therefore, requires no limits. Because the xenon distribution produced at THERMAL POWER levels less than RTP does affect the power distribution as power is increased, unanalyzed xenon and power distribution is prevented by limiting the accumulated penalty deviation time.

For surveillance of the power range channels performed according to SR 3.3.1.6, Note 4 allows deviation outside the target band for 16 hours and no penalty deviation time is accumulated. Some deviation in the AFD is required for doing the NIS calibration with the incore detector system.

AFD requirements are applicable in MODE 1 above 15% RTP. Above 50% RTP, the combination of THERMAL POWER and core peaking factors are the core parameters of primary importance in safety analyses (Ref. 1).

Between 15% RTP and 90% RTP, this LCO is applicable to ensure that the distributions of xenon are consistent with safety analysis assumptions.

BASES

LCO (continued)

At or below 15% RTP and for lower operating MODES, the stored energy in the fuel and the energy being transferred to the reactor coolant are low. The value of the AFD in these conditions does not affect the consequences of the design basis events.

Low signal levels in the excore channels may preclude obtaining valid AFD signals below 15% RTP.

ACTIONS

A.1

With the AFD outside the target band and THERMAL POWER ≥ 90% RTP, the assumptions used in the accident analyses may be violated with respect to the maximum heat generation. Therefore, a Completion Time of 15 minutes is allowed to restore the AFD to within the target band because xenon distributions change little in this relatively short time.

B.1

If the AFD cannot be restored within the target band, then reducing THERMAL POWER to < 90% RTP places the core in a condition that has been analyzed and found to be acceptable, provided that the AFD is within the acceptable operation limits provided in the COLR.

The allowed Completion Time of 15 minutes provides an acceptable time to reduce power to < 90% RTP without allowing the plant to remain in an unanalyzed condition for an extended period of time.

C.1

With THERMAL POWER < 90% RTP but ≥ 50% RTP, operation with the AFD outside the target band is allowed for up to 1 hour if the AFD is within the acceptable operation limits provided in the COLR. With the AFD within these limits, the resulting axial power distribution is acceptable as an initial condition for accident analyses assuming the then existing xenon distributions. The 1 hour cumulative penalty deviation time restricts the extent

BASES

ACTIONS

C.1 (continued)

of xenon redistribution. Without this limitation, unanalyzed xenon axial distributions may result from a different pattern of xenon buildup and decay. The reduction to a power level < 50% RTP puts the reactor at a THERMAL POWER level at which the AFD is not a significant accident analysis parameter.

If the indicated AFD is outside the target band and outside the acceptable operation limits provided in the COLR, the peaking factors assumed in accident analysis may be exceeded with the existing xenon condition. (Any AFD within the target band is acceptable regardless of its relationship to the acceptable operation limits.) The Completion Time of 30 minutes allows for a prompt, yet orderly, reduction in power.

Condition C is modified by a Note that requires that Required Action C.1 must be completed whenever this Condition is entered.

SURVEILLANCE REQUIREMENTS

SR 3.2.3.1

The AFD is monitored on an automatic basis using the unit process computer that has an AFD monitor alarm. The computer determines the 1 minute average of each of the OPERABLE excore detector outputs and provides an alarm if the AFDs for two or more OPERABLE excore channels are outside the target band and the THERMAL POWER is > 90% RTP. During operation at THERMAL POWER levels < 90% RTP but > 15% RTP, the computer provides an alarm when the cumulative penalty deviation time is > 1 hour in the previous 24 hours.

This Surveillance verifies that the AFD as indicated by the NIS excore channels is within the target band and consistent with the status of the AFD monitor alarm. The Surveillance Frequency of 7 days is adequate because the AFD is controlled by the operator and monitored by the process computer. Furthermore, any deviations of the AFD from the target band that is not alarmed should be readily noticed.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.2.3.2

With the AFD monitor alarm inoperable, the AFD is monitored to detect operation outside of the target band and to compute the penalty deviation time. During operation at ≥ 90% RTP, the AFD is monitored at a Surveillance Frequency of 15 minutes to ensure that the AFD is within its limits at high THERMAL POWER levels. At power levels < 90% RTP, but > 15% RTP, the Surveillance Frequency is reduced to 1 hour because the AFD may deviate from the target band for up to 1 hour using the methodology of Parts B and C of this LCO to calculate the cumulative penalty deviation time before corrective action is required.

SR 3.2.3.2 is modified by a Note that states that monitored and logged values of the AFD are assumed to exist for the preceding 24 hour interval in order for the operator to compute the cumulative penalty deviation time. The AFD should be monitored more frequently in periods of operation for which the power level or control bank positions are changing to allow corrective measures when the AFD is more likely to move outside the target band.

SR 3.2.3.3

This Surveillance requires that the target flux difference is updated at a Frequency of 31 effective full power days (EFPD) to account for small changes that may occur in the target flux differences in that period due to burnup by performing SR 3.2.3.4. Alternatively, linear interpolation between the most recent measurement of the target flux differences and a predicted end of cycle value provides a reasonable update.

SR 3.2.3.4

Measurement of the target flux difference is accomplished by taking a flux map when the core is at equilibrium xenon conditions, preferably at high power levels with the control banks nearly withdrawn. This flux map provides the equilibrium xenon axial power distribution from which the target value can be determined. The target flux difference varies slowly with core burnup.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.2.3.4 (continued)

A Frequency of 31 EFPD after each refueling and 92 EFPD thereafter for remeasuring the target flux differences adjusts the target flux difference for each excore channel to the value measured at steady state conditions. This is the basis for the CAOC. Remeasurement at this Surveillance interval also establishes the AFD target flux difference values that account for changes in incore excore calibrations that may have occurred in the interim.

A Note modifies this SR to allow the predicted end of cycle AFD from the cycle nuclear design to be used to determine the initial target flux difference after each refueling.

REFERENCES

1. FSAR, Chapter 7.

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.4 QUADRANT POWER TILT RATIO (QPTR)

BASES

BACKGROUND

The QPTR limit ensures that the gross radial power distribution remains consistent with the design values used in the safety analyses. Precise radial power distribution measurements are made after refueling, and periodically during power operation.

The power density at any point in the core must be limited so that the fuel design criteria are maintained. Together, LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)," LCO 3.2.4, and LCO 3.1.6, "Control Bank Insertion Limits," provide limits on process variables that characterize and control the three dimensional power distribution of the reactor core. Control of these variables ensures that the core operates within the fuel design criteria and that the power distribution remains within the bounds used in the safety analyses.

APPLICABLE SAFETY ANALYSES

This LCO precludes core power distributions that violate the following fuel design criteria:

a. During a large break loss of coolant accident, the peak cladding temperature must not exceed 2200°F (Ref. 1);

b. During a loss of forced reactor coolant flow accident, there must be at least 95% probability at the 95% confidence level (the 95/95 departure from nucleate boiling (DNB) criterion) that the hot fuel rod in the core does not experience a DNB condition (Ref. 2);

c. During an ejected rod accident, the energy deposition to the fuel must not exceed 225 calories/gram for non-irradiated fuel and 200 calories/gram for irradiated fuel (Ref. 3); and

BASES

APPLICABLE SAFETY ANALYSES (continued)

d. The control rods must be capable of shutting down the reactor with a minimum required SDM with the highest worth control rod stuck fully withdrawn (Ref. 4).

The LCO limits on the AFD, the QPTR, the Heat Flux Hot Channel Factor ($F_Q(Z)$), the Nuclear Enthalpy Rise Hot Channel Factor ($F^N_{\Delta H}$), and control bank insertion are established to preclude core power distributions that exceed the safety analyses limits.

The QPTR limits ensure that $F^N_{\Delta H}$ and $F_Q(Z)$ remain below their limiting values by preventing an undetected change in the gross radial power distribution.

In MODE 1, the $F^N_{\Delta H}$ and $F_Q(Z)$ limits must be maintained to preclude core power distributions from exceeding design limits assumed in the safety analyses.

The QPTR satisfies Criterion 2 of 10 CFR 50.36.

LCO

The QPTR limit of 1.02, at which corrective action is required, provides a margin of protection for both the DNB ratio and linear heat generation rate contributing to excessive power peaks resulting from X-Y plane power tilts. A limiting QPTR of 1.02 can be tolerated before the margin for uncertainty in $F_Q(Z)$ and ($F^N_{\Delta H}$) is possibly challenged.

APPLICABILITY

The QPTR limit must be maintained in MODE 1 with THERMAL POWER > 50% RTP to prevent core power distributions from exceeding the design limits.

Applicability in MODE 1 ≤ 50% RTP and in other MODES is not required because there is either insufficient stored energy in the fuel or insufficient energy being transferred to the reactor coolant to require the implementation of a QPTR limit on the distribution of core power. The QPTR limit in these conditions is, therefore, not important. Note that the $F^N_{\Delta H}$ and $F_Q(Z)$ LCOs

BASES

APPLICABILITY (continued)

still apply, but allow progressively higher peaking factors at 50% RTP or lower.

ACTIONS

A.1

With the QPTR exceeding its limit, a power level reduction of 3% RTP for each 1% by which the QPTR exceeds 1.00 is a conservative tradeoff of total core power with peak linear power. The Completion Time of 2 hours allows sufficient time to identify the cause and correct the tilt. Note that the power reduction itself may cause a change in the tilted condition.

A.2

After completion of Required Action A.1, the QPTR may still exceed the specified limit. As such, any additional changes in the QPTR are detected by requiring a check of the QPTR once per 12 hours thereafter. If the QPTR continues to increase, THERMAL POWER has to be reduced accordingly. A 12 hour Completion Time is sufficient because any additional change in QPTR would be relatively slow.

A.3

The peaking factors $F^N_{\Delta H}$ and $F_Q(Z)$ are of primary importance in ensuring that the power distribution remains consistent with the initial conditions used in the safety analyses. Performing SRs on $F^N_{\Delta H}$ and $F_Q(Z)$ within the Completion Time of 24 hours ensures that these primary indicators of power distribution are within their respective limits. A Completion Time of 24 hours takes into consideration the rate at which peaking factors are likely to change, and the time required to stabilize the plant and perform a flux map. If these peaking factors are not within their limits, the Required Actions of these Surveillances provide an appropriate response for the abnormal condition. If the QPTR remains above its specified limit, the peaking factor surveillances are required each 7 days thereafter to evaluate $F^N_{\Delta H}$ and $F_Q(Z)$ with changes in power distribution. Relatively small

BASES

ACTIONS

A.3 (continued)

changes are expected due to either burnup and xenon redistribution or correction of the cause for exceeding the QPTR limit.

A.4

Although $F^N_{\Delta H}$ and $F_Q(Z)$ are of primary importance as initial conditions in the safety analyses, other changes in the power distribution may occur as the QPTR limit is exceeded and may have an impact on the validity of the safety analysis. A change in the power distribution can affect such reactor parameters as bank worths and peaking factors for rod malfunction accidents. When the QPTR exceeds its limit, it does not necessarily mean a safety concern exists. It does mean that there is an indication of a change in the gross radial power distribution that requires an investigation and evaluation that is accomplished by examining the incore power distribution. Specifically, the core peaking factors and the quadrant tilt must be evaluated because they are the factors that best characterize the core power distribution. This re-evaluation is required to ensure that, before increasing THERMAL POWER to above the limit of Required Action A.1, the reactor core conditions are consistent with the assumptions in the safety analyses.

A.5

If the QPTR has exceeded the 1.02 limit and a re-evaluation of the safety analysis is completed and shows that safety requirements are met, the excore detectors are recalibrated to show a 1.00 QPTR prior to increasing THERMAL POWER to above the limit of Required Action A.1. This is done to detect any subsequent significant changes in QPTR.

Required Action A.5 is modified by a Note that states that the QPT is not normalized until after the re-evaluation of the safety analysis has determined that core conditions at RTP are within the safety analysis assumptions (i.e., Required Action A.4). This Note is intended to prevent any ambiguity about the required sequence of actions.

BASES

ACTIONS (continued)

A.6

Once the flux tilt is normalized (i.e., Required Action A.5 is performed), it is acceptable to return to full power operation. However, as an added check that the core power distribution at RTP is consistent with the safety analysis assumptions, Required Action A.6 requires verification that $F_Q(Z)$ and $F^N_{\Delta H}$ are within their specified limits within 24 hours of reaching RTP. As an added precaution, if the core power does not reach RTP within 24 hours, but is increased slowly, then the peaking factor surveillances must be performed within 48 hours of the time when the ascent to power was begun. These Completion Times are intended to allow adequate time to increase THERMAL POWER to above the limit of Required Action A.1, while not permitting the core to remain with unconfirmed power distributions for extended periods of time.

Required Action A.6 is modified by a Note that states that the peaking factor surveillances may only be done after the excore detectors have been calibrated to show 1.00 tilt ratio (i.e., Required Action A.5). The intent of this Note is to have the peaking factor surveillances performed at operating power levels, which can only be accomplished after the excore detectors are calibrated to show 1.00 tilt ratio and the core returned to power.

B.1

If Required Actions A.1 through A.6 are not completed within their associated Completion Times, the unit must be brought to a MODE or condition in which the requirements do not apply. To achieve this status, THERMAL POWER must be reduced to < 50% RTP within 4 hours. The allowed Completion Time of 4 hours is reasonable, based on operating experience regarding the amount of time required to reach the reduced power level without challenging plant systems.

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SR 3.2.4.1

SR 3.2.4.1 is modified by two Notes. Note 1 allows QPTR to be calculated with three power range channels if THERMAL POWER is < 75% RTP and the input from one Power Range Neutron Flux channel is inoperable. Note 2 allows performance of SR 3.2.4.2 in lieu of SR 3.2.4.1.

This Surveillance verifies that the QPTR, as indicated by the Nuclear Instrumentation System (NIS) excore channels, is within its limits. The Frequency of 7 days takes into account other indications and alarms available to the operator in the control room. For those causes of QPT that occur quickly (e.g., a dropped rod), there typically are other indications of abnormality that prompt a verification of core power tilt.

SR 3.2.4.2

This Surveillance is modified by a Note, which states that it is not required until 24 hours after the input from one or more Power Range Neutron Flux channels are inoperable and the THERMAL POWER is ≥ 75% RTP.

With an NIS power range channel inoperable, tilt monitoring for a portion of the reactor core becomes degraded. Large tilts are likely detected with the remaining channels, but the capability for detection of small power tilts in some quadrants is decreased. Performing SR 3.2.4.2 at a Frequency of 12 hours provides an accurate alternative means for ensuring that any tilt remains within its limits.

For purposes of monitoring the QPTR when one power range channel is inoperable, the moveable incore detectors are used to confirm that the normalized symmetric power distribution is consistent with the indicated QPTR and any previous data indicating a tilt. The incore detector monitoring is performed with a full incore flux map or at least two thimbles per quadrant.

The symmetric thimble flux map can be used to measure symmetric thimble "tilt." This can be compared to a reference symmetric

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SURVEILLANCE REQUIREMENTS

SR 3.2.4.2 (continued)

thimble tilt, from the most recent full core flux map, to generate an incore QPTR. Therefore, incore QPTR can be used to confirm that QPTR is within limits.

With one NIS channel inoperable, the indicated tilt may be changed from the value indicated with all four channels OPERABLE. To confirm that no change in tilt has actually occurred, which might cause the QPTR limit to be exceeded, the incore result may be compared against previous flux maps either using the symmetric thimbles as described above or a complete flux map.

REFERENCES

1. 10 CFR 50.46.
2. FSAR Section 14.1.6.
3. FSAR Section 14.2.6.
4. FSAR Section 3.1.

B 3.3 INSTRUMENTATION

B 3.3.1 Reactor Protection System (RPS) Instrumentation

BASES

BACKGROUND

The RPS initiates a unit shutdown, based on the values of selected unit parameters, to protect against violating the core fuel design limits and Reactor Coolant System (RCS) pressure boundary during anticipated operational occurrences (AOOs) and to assist the Engineered Safety Features (ESF) Systems in mitigating accidents.

The protection and monitoring systems have been designed to assure safe operation of the reactor. This is achieved by specifying limiting safety system settings (LSSS) in terms of parameters directly monitored by the RPS, as well as specifying LCOs on other reactor system parameters and equipment performance.

The LSSS, defined in this specification as the Allowable Value, in conjunction with the LCOs, establish the threshold for protective system action to prevent exceeding acceptable limits during Design Basis Accidents (DBAs).

During AOOs, which are those events expected to occur one or more times during the unit life, the acceptable limits are:

1. The Departure from Nucleate Boiling Ratio (DNBR) shall be maintained above the Safety Limit (SL) value to prevent departure from nucleate boiling (DNB);

2. Fuel centerline melt shall not occur; and

3. The RCS pressure SL of 2735 psig shall not be exceeded.

Operation within the SLs of Specification 2.0, "Safety Limits (SLs)," also maintains the above values and assures that offsite dose will be within the 10 CFR 50 and 10 CFR 100 criteria during AOOs.

Accidents are events that are analyzed even though they are not expected to occur during the unit life. The acceptable limit

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during accidents is that offsite dose shall be maintained within an acceptable fraction of 10 CFR 100 limits. Different accident categories are allowed a different fraction of these limits, based on probability of occurrence. Meeting the acceptable dose limit for an accident category is considered having acceptable consequences for that event.

The RPS instrumentation is segmented into four distinct but interconnected modules as described in FSAR, Chapter 7 (Ref. 1), and as identified below:

1. Field transmitters or process sensors: provide a measurable electronic signal based upon the physical characteristics of the parameter being measured;

2. Nuclear Instrumentation System (NIS), field contacts, and protection channels: provides signal conditioning, bistable setpoint comparison, process algorithm actuation, compatible electrical signal output to protection system devices, and control board/control room/miscellaneous indications;

3. RPS automatic initiation relay logic, including input, logic, and output: initiates proper unit shutdown in accordance with the defined logic, which is based on the bistable outputs from the signal process control and protection system; and

4. Reactor trip switchgear, including reactor trip breakers (RTBs) and bypass breakers: provides the means to interrupt power to the control rod drive mechanisms (CRDMs) and allows the rod cluster control assemblies (RCCAs), or "rods," to fall into the core and shut down the reactor. The bypass breakers allow testing of the RTBs at power.

<u>Field Transmitters or Sensors</u>

To meet the design demands for redundancy and reliability, more than one, and often as many as four, field transmitters or sensors are used to measure unit parameters. To account for the

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calibration tolerances and instrument drift, which are assumed to occur between calibrations, statistical allowances are provided in the Allowable Values. The OPERABILITY of each transmitter or sensor can be evaluated when its "as found" calibration data are compared against its documented Allowable Value.

Signal Process Control and Protection System

Generally, three or four channels of process control equipment are used for the signal processing of unit parameters measured by the field instruments. The process control equipment provides signal conditioning, comparable output signals for instruments located on the main control board, and comparison of measured input signals with setpoints established to ensure that actuation will occur within the limits assumed in the accident analyses (Ref. 3). If the measured value of a unit parameter exceeds the predetermined setpoint, an output from a bistable is forwarded to the RPS relay logic. Channel separation is maintained up to and through the actuation logic. However, not all unit parameters require four channels of sensor measurement and signal processing. Some unit parameters provide input only to the RPS relay logic, while others provide input to the RPS relay logic, the main control board, the unit computer, and one or more control systems.

Generally, if a parameter is used only for input to the protection circuits, three channels with a two-out-of-three logic are sufficient to provide the required reliability and redundancy. If one channel fails in a direction that would not result in a partial Function trip, the Function is still OPERABLE with a two-out-of-two logic. If one channel fails, such that a partial Function trip occurs, a trip will not occur and the Function is still OPERABLE with a one-out-of-two logic.

Generally, if a parameter is used for input to the RPS relay logic and a control function, four channels with a two-out-of-four logic are sufficient to provide the required reliability and redundancy. The circuit must be able to withstand both an input failure to the control system, which may then require the protection function actuation, and a single

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failure in the other channels providing the protection function actuation. Again, a single failure will neither cause nor prevent the protection function actuation. These requirements are described in IEEE-279-1968 (Ref. 4). The actual number of channels required for each unit parameter is specified in Reference 1 and discussed later in these Technical Specification Bases.

Two logic channels are required to ensure no single random failure of a logic channel will disable the RPS. The logic channels are designed such that testing required while the reactor is at power may be accomplished without causing trip.

Trip Setpoints and Allowable Values

The following describes the relationship between the safety limit, analytical limit, allowable value and channel component calibration acceptance criteria:

a. A Safety Limit (SL) is a limit on the combination of THERMAL POWER, RCS highest loop average temperature, and RCS pressure needed to protect the integrity of physical barriers that guard against the uncontrolled release of radioactivity (i.e., fuel, fuel cladding, RCS pressure boundary and containment). The safety limits are identified in Technical Specification 2.0, Safety Limits (SLs).

b. An Analytical Limit (AL) is the trip actuation point used as an input to the accident analyses presented in FSAR, Chapter 14 (Ref. 3). Analytical limits are developed from event analyses models which consider parameters such as process delays, rod insertion times, reactivity changes, instrument response times, etc. An analytical limit for a trip actuation point is established at a point that will ensure that a Safety Limit (SL) is not exceeded.

c. An Allowable Value (AV) is the limiting actuation point for the entire channel of a trip function that will ensure, within the required level of confidence, that sufficient

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allocation exists between this actual trip function actuation point and the analytical limit. The Allowable Value is more conservative than the Analytical Limit to account for instrument uncertainties that either are not present or are not measured during periodic testing. Channel uncertainties that either are not present or are not measured during periodic testing may include design basis accident temperature and radiation effects (Ref. 5) or process dependent effects. The channel allowable value for each RPS function is controlled by Technical Specifications and is listed in Table 3.3.1-1, Reactor Protection System Instrumentation.

d. <u>Calibration acceptance criteria</u> (i.e., setpoints) are established by plant administrative programs for the components of a channel (i.e., required sensor, alarm, interlock, display, and trip function). The calibration acceptance criteria are established to ensure, within the required level of confidence, that the Allowable Value for the entire channel will not be exceeded during the calibration interval.

A description of the methodology used to calculate the channel allowable values and calibration acceptance criteria is provided in References 6 and 8.

Setpoints in accordance with the Allowable Value ensure that SLs are not violated during AOOs (and that the consequences of DBAs will be acceptable, providing the unit is operated from within the LCOs at the onset of the AOO or DBA and the equipment functions as designed).

Each channel of the relay logic protection system can be tested on line to verify that the signal or setpoint accuracy is within the specified allowance requirements of calculations performed in accordance with Reference 6 that are based on analytical limits consistent with Reference 3. Once a designated channel is taken out of service for testing, a simulated signal is injected in place of the field instrument signal. The process equipment for

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the channel in test is then tested, verified, and calibrated. SRs for the channels are specified in the SRs section.

The Allowable Values listed in Table 3.3.1-1 and the Trip Setpoints calculated to ensure that Allowable Values are not exceeded during the calibration interval are based on the methodology described in Reference 6, which incorporates all of the known uncertainties applicable for each channel. All field sensors and signal processing equipment for these channels are assumed to operate within the allowances of these uncertainty magnitudes.

Relay Logic Protection System

Relay logic is used for the decision logic processing of outputs from the signal processing equipment bistables. To meet the redundancy requirements, two trains of relay logic, each performing the same functions, are provided. If one train is taken out of service for maintenance or test purposes, the second train will provide reactor trip and/or ESF actuation for the unit. If both trains are taken out of service or placed in test, a reactor trip will result. Each train is packaged in its own cabinet for physical and electrical separation to satisfy separation and independence requirements. The system has been designed to trip in the event of a loss of power, directing the unit to a safe shutdown condition.

The relay logic performs the decision logic for actuating a reactor trip or ESF actuation, generates the electrical output signal that will initiate the required trip or actuation, and provides the status, permissive, and annunciator output signals to the control room.

The bistable outputs from the signal processing equipment are sensed by the relay logic equipment and combined into logic matrices that represent combinations indicative of various unit upset and accident transients. If a required logic matrix combination is completed, the system will initiate a reactor trip or send actuation signals via master and slave relays to those components whose aggregate Function best serves to alleviate the

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condition and restore the unit to a safe condition. Examples are given in the Applicable Safety Analyses, LCO, and Applicability sections of this Bases.

Reactor Trip Breakers

The RTBs are in the electrical power supply line from the control rod drive motor generator set power supply to the CRDMs. Opening of the RTBs interrupts power to the CRDMs, which allows the shutdown rods and control rods to fall into the core by gravity. Each RTB is equipped with a bypass breaker to allow testing of the RTB while the unit is at power. During normal operation the output from the reator protection system is a voltage signal that energizes the undervoltage coils in the RTBs and bypass breakers, if in use. When the required logic matrix combination is completed, the reator protection system output voltage signal is removed, the undervoltage coils are de-energized, the breaker trip lever is actuated by the de-energized undervoltage coil, and the RTBs and bypass breakers are tripped open. This allows the shutdown rods and control rods to fall into the core. In addition to the de-energization of the undervoltage coils, each breaker is also equipped with a shunt trip device that is energized to trip the breaker open upon receipt of a reactor trip signal from the reactor protection system. Either the undervoltage coil or the shunt trip mechanism is sufficient by itself, thus providing a diverse trip mechanism.

There are two reactor trip breakers in series so that opening either will interrupt power to the control rod drive mechanisms (CRDMs) and allow the rod cluster control assemblies (RCCAs), or "rods," to fall into the core and shut down the reactor. Each reactor trip breaker has a parallel reactor trip bypass breaker that is normally open. This feature allows testing of the reactor trip breakers at power. A trip signal from RPS logic train A will trip reactor trip breaker A and reactor trip bypass breaker B; and, a trip signal from logic train B will trip reactor trip breaker B and reactor trip bypass breaker A. During normal operation, both reactor trip breakers are closed and both reactor trip bypass breakers are open. An interlock trips both reactor trip bypass breakers if an attempt is made to close a

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reactor trip bypass breaker when the other reactor trip bypass breaker is already closed.

A trip breaker train consists of both the reactor trip breaker and reactor trip bypass breaker associated with a single RPS logic train if the breaker is racked in, closed, and capable of supplying power to the CRD System. Thus, the train consists of the main breaker; or, the main breaker and bypass breaker associated with this same RPS logic train if both the breaker and bypass are racked in, closed, and capable of supplying power to the CRD System.

The RPS decision logic Functions are described in the functional diagrams included in Reference 2. In addition to the reactor protection and ESFAS trips, the various "permissive interlocks" that are associated with unit conditions are also described.

When any one RPS train is taken out of service for testing, the other train is capable of providing unit monitoring and protection until the testing has been completed.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The RPS functions to maintain the Safety Limits (SLs) during all Abnormal Operating Occurences (AOOs) and mitigates the consequences of DBAs in all MODES in which the Rod Control system is capable of rod withdrawal and one or more rods not fully inserted.

Each of the analyzed accidents and transients can be detected by one or more RPS Functions. The accident analysis described in Reference 3 takes credit for most RPS trip Functions. RPS trip Functions not specifically credited in the accident analysis are qualitatively credited in the safety analysis and the NRC staff approved licensing basis. These RPS trip Functions may provide protection for conditions that do not require dynamic transient analysis to demonstrate Function performance. They may also serve as backups to RPS trip Functions that were credited in the accident analysis.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The LCO requires all instrumentation performing an RPS Function, listed in Table 3.3.1-1 in the accompanying LCO, to be OPERABLE. Failure of any instrument renders the affected channel(s) inoperable and reduces the reliability of the affected Functions.

The LCO generally requires OPERABILITY of four or three channels in each instrumentation Function, two channels of Manual Reactor Trip, and two trains in each Automatic Trip Logic Function. Generally, four OPERABLE instrumentation channels in a two-out-of-four configuration are required when one RPS channel is also used as a control system input. Isolation amplifiers prevent a control system failure from affecting the protection system (Ref. 1). This configuration accounts for the possibility of the shared channel failing in such a manner that it creates a transient that requires RPS action. In this case, the RPS will still provide protection, even with random failure of one of the other three protection channels. Three OPERABLE instrumentation channels in a two-out-of-three configuration are generally required when there is no potential for control system and protection system interaction that could simultaneously create a need for RPS trip and disable one RPS channel. The two-out-of-three and two-out-of-four configurations allow one channel to be tripped during maintenance or testing without causing a reactor trip. Specific exceptions to the above general philosophy exist and are discussed below.

Reactor Protection System Functions

The safety analyses and OPERABILITY requirements applicable to each RPS Function are discussed below:

1. Manual Reactor Trip

The Manual Reactor Trip ensures that the control room operator can initiate a reactor trip at any time by using either of two reactor trip push buttons in the control room. A Manual Reactor Trip accomplishes the same results as any one of the automatic trip Functions. It is used by

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

the reactor operator to shut down the reactor whenever any parameter is rapidly trending toward its Trip Setpoint.

The LCO requires two Manual Reactor Trip channels to be OPERABLE. Each channel is controlled by a manual reactor trip push button. Each channel activates the reactor trip breaker in both trains. Two independent channels are required to be OPERABLE so that no single random failure will disable the Manual Reactor Trip Function.

In MODE 1 or 2, manual initiation of a reactor trip must be OPERABLE. These are the MODES in which the shutdown rods and/or control rods are partially or fully withdrawn from the core. In MODE 3, 4, or 5, the manual initiation Function must also be OPERABLE if the shutdown rods or control rods are withdrawn or the Rod Control System is capable of withdrawing the shutdown rods or the control rods. In this condition, inadvertent control rod withdrawal is possible. In MODE 3, 4, or 5, manual initiation of a reactor trip does not have to be OPERABLE if the Rod Control System is not capable of withdrawing the shutdown rods or control rods and if all rods are fully inserted. If the rods cannot be withdrawn from the core, or all of the rods are inserted there is no need to be able to trip the reactor. In MODE 6, neither the shutdown rods nor the control rods are permitted to be withdrawn and the CRDMs are disconnected from the control rods and shutdown rods. Therefore, the manual initiation Function is not required.

2. Power Range Neutron Flux

The NIS power range detectors are located external to the reactor vessel and measure neutrons leaking from the core. The NIS power range detectors provide input to the Rod Control System and Turbine Control System. Four channels of NIS are required because the actuation logic must be able to withstand an input failure to the control system and a single failure in the other three channels providing the protection function actuation. Note that this Function

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

also provides a signal to prevent automatic and manual rod withdrawal prior to initiating a reactor trip. Limiting further rod withdrawal may terminate the transient and eliminate the need to trip the reactor.

a. Power Range Neutron Flux-High

The Power Range Neutron Flux – High trip Function ensures that protection is provided, from all power levels, against a positive reactivity excursion leading to DNB during power operations. These can be caused by rod withdrawal or reductions in RCS temperature.

The LCO requires all four of the Power Range Neutron Flux – High channels to be OPERABLE. These channels are considered OPERABLE during required Surveillance tests that require insertion of a test signal if the channel remains untripped and capable of tripping due to an increasing neutron flux signal.

In MODE 1 or 2, when a positive reactivity excursion could occur, the Power Range Neutron Flux – High trip must be OPERABLE. This Function will terminate the reactivity excursion and shut down the reactor prior to reaching a power level that could damage the fuel. In MODE 3, 4, 5, or 6, the NIS power range detectors cannot detect neutron levels in this range. In these MODES, the Power Range Neutron Flux – High does not have to be OPERABLE because the reactor is shut down and reactivity excursions into the power range are extremely unlikely. Other RPS Functions and administrative controls provide protection against reactivity additions when in MODE 3, 4, 5, or 6.

The Power Range Neutron Flux-High Allowable Value and Trip Setpoint are in accordance with Consolidated Edison Company of New York, Inc. Indian Point Nuclear Generating Station Unit No. 3 Plant Manual Volume VI:

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Precautions, Limitations, and Setpoints, March 1975 (Ref. 8).

b. Power Range Neutron Flux-Low

The LCO requirement for the Power Range Neutron Flux - Low trip Function ensures that protection is provided against a positive reactivity excursion from low power or subcritical conditions.

The LCO requires all four of the Power Range Neutron Flux - Low channels to be OPERABLE.

In MODE 1, below the Power Range Neutron Flux (P-10 setpoint), and in MODE 2, the Power Range Neutron Flux - Low trip must be OPERABLE. This Function may be manually blocked by the operator when two out of four power range channels are greater than approximately 10% RTP (P-10 setpoint). This Function is automatically unblocked when three out of four power range channels are below the P-10 setpoint. Above the P-10 setpoint, positive reactivity additions are mitigated by the Power Range Neutron Flux - High trip Function.

In MODE 3, 4, 5, or 6, the Power Range Neutron Flux - Low trip Function does not have to be OPERABLE because the reactor is shut down and the NIS power range detectors cannot detect neutron levels in this range. Other RPS trip Functions and administrative controls provide protection against positive reactivity additions or power excursions in MODE 3, 4, 5, or 6.

The Power Range Neutron Flux-Low Allowable Value and Trip Setpoint are in accordance with Consolidated Edison Company of New York, Inc. Indian Point Nuclear Generating Station Unit No. 3 Plant Manual Volume VI: Precautions, Limitations, and Setpoints, March 1975 (Ref. 8).

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

3. Intermediate Range Neutron Flux

The Intermediate Range Neutron Flux trip Function ensures that protection is provided against an uncontrolled RCCA bank rod withdrawal accident from a subcritical condition during startup. This trip Function provides redundant protection to the Power Range Neutron Flux – Low Setpoint trip Function. Therefore, only one of the two channels of Intermediate Range Neutron Flux is Required to be OPERABLE in the Applicable MODES. Either of the two channels can be used to satisfy this requirement. The NIS intermediate range detectors are located external to the reactor vessel and measure neutrons leaking from the core. The NIS intermediate range detectors do not provide any input to control systems. Note that this Function also provides a signal to prevent automatic and manual rod withdrawal prior to initiating a reactor trip. Limiting further rod withdrawal may terminate the transient and eliminate the need to trip the reactor.

The LCO requires one channel of Intermediate Range Neutron Flux to be OPERABLE. One OPERABLE channel is sufficient to provide redundant protection to the Power Range Neutron Flux – Low Setpoint trip Function.

Table 3.3.1-1 identifies the Technical Specification Allowable Value for this trip function as not applicable (NA) because LCO 3.3.1, Function 2.b, Power Range Neutron Flux-Low, is used to bound the analysis for an uncontrolled control rod assembly withdrawal from a subcritical condition. The allowable value required for OPERABILITY of this trip function is 25% RTP. This allowable value was established based on Indian Point Nuclear Generating Station Unit No. 3 Plant Manual Volume VI: Precautions, Limitations, and Setpoints, March 1975, (Ref. 8).

Because this trip Function is important only during startup, there is generally no need to disable channels for testing while the Function is required to be OPERABLE. Therefore, a third channel is unnecessary.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The Intermediate Range Neutron Flux trip must be OPERABLE in MODE 1 below the P-10 setpoint, and in MODE 2 above the P-6 setpoint, when there is a potential for an uncontrolled RCCA bank rod withdrawal accident during reactor startup. Above the P-10 setpoint, the Power Range Neutron Flux – High Setpoint trip provides core protection for a rod withdrawal accident. In MODE 2, below the P-6 setpoint, the source Range Neutron Flux Trip provides backup core protection for reactivity accidents. In MODE 3, 4, or 5, the Intermediate Range Neutron Flux trip does not have to be OPERABLE because the control rods must be fully inserted and only the shutdown rods may be withdrawn. The reactor cannot be started up in this condition. The core also has the required SDM to mitigate the consequences of a positive reactivity addition accident. In MODE 6, all rods are fully inserted and the core has a required increased SDM. Also, the NIS intermediate range detectors cannot detect neutron levels present in this MODE.

4. <u>Source Range Neutron Flux</u>

The LCO requirement for the Source Range Neutron Flux trip Function ensures that protection is provided against an uncontrolled RCCA bank rod withdrawal accident from a subcritical condition during startup. This trip Function provides redundant protection to the Power Range Neutron Flux – Low trip Function. Therefore, only one of the two channels of Source Range Neutron Flux is Required to be OPERABLE in the Applicable MODES. Either of the two channels can be used to satisfy this requirement. In MODES 3, 4, and 5, administrative controls also prevent the uncontrolled withdrawal of rods. The NIS source range detectors are located external to the reactor vessel and measure neutrons leaking from the core. The NIS source range detectors do not provide any inputs to control systems. The source range trip is the only RPS automatic protection function required in MODES 3, 4, and 5 when rods are capable of withdrawal and one or more rods are not fully inserted. Therefore, the functional capability at the specified Allowable Values is assumed to be available.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The LCO requires one channel of Source Range Neutron Flux to be OPERABLE. One OPERABLE channel is sufficient to provide redundant protection to the Power Range Neutron Flux – Low Setpoint trip Function.

Table 3.3.1-1 identifies the Technical Specification Allowable Value for this trip function as not applicable (NA) because LCO 3.3.1, Function 2.b, Power Range Neutron Flux-Low, is used to bound the analysis for an uncontrolled control rod assembly withdrawal from a subcritical condition. The allowable value required for OPERABILITY of this trip function is 1.0 E+5 counts per second. This allowable value was established based on Indian Point Nuclear Generating Station Unit No. 3 Plant Manual Volume VI: Precautions, Limitations, and Setpoints, March 1975, (Ref. 8).

The Source Range Neutron Flux Function provides protection for control rod withdrawal from subcritical. The Function also provides visual neutron flux indication in the control room.

In MODE 2 when below the P-6 setpoint and in MODES 3, 4, and 5, when there is a potential for an uncontrolled RCCA bank withdrawal accident, the Source Range Neutron Flux trip must be OPERABLE. Above the P-6 setpoint, the Intermediate Range Neutron Flux trip and the Power Range Neutron Flux – Low trip will provide core protection for reactivity accidents. Above the P-6 setpoint, the NIS source range detectors are de-energized.

In MODEs 3, 4, and 5 with all rods fully inserted and the Rod Control System not capable of rod withdrawal, and in MODE 6, the outputs of this function to the RPS logic are not required to be OPERABLE. The requirements for the NIS source range detectors in MODE 6 are addressed in LCO 3.9.2, "Nuclear Instrumentation."

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

5. Overtemperature ΔT

The Overtemperature ΔT trip Function is provided to ensure that the design limit DNBR is met. This trip Function also limits the range over which the Overpower ΔT trip Function must provide protection. The inputs to the Overtemperature ΔT trip include pressure, coolant temperature, axial power distribution, and reactor power as indicated by loop ΔT assuming full reactor coolant flow. Protection from violating the DNBR limit is assured for those transients that are slow with respect to delays from the core to the measurement system. The Overtemperature ΔT trip Function uses each loop's ΔT as a measure of reactor power and is compared with a setpoint that is automatically varied with the following parameters:

- reactor coolant average temperature – the Trip Setpoint is varied to correct for changes in coolant density and specific heat capacity with changes in coolant temperature;
- pressurizer pressure – the Trip Setpoint is varied to correct for changes in system pressure; and
- axial power distribution – $f(\Delta I)$, the Trip Setpoint is varied to account for imbalances in the axial power distribution as detected by the NIS upper and lower power range detectors. If axial peaks are greater than the Technical Specification limit, as indicated by the difference between the upper and lower NIS power range detectors, the Trip Setpoint is reduced in accordance with Note 1 of Table 3.3.1-1.

Dynamic compensation is included for system piping delays from the core to the temperature measurement system.

The Overtemperature ΔT trip Function is calculated for each loop as described in Note 1 of Table 3.3.1-1. Trip occurs if Overtemperature ΔT is indicated in two loops. The pressure and temperature signals are used for other control

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

functions. Therefore, the actuation logic is designed to withstand an input failure to the control system, which may then require the protection function actuation, and a single failure in the other channels providing the protection function actuation. Note that this Function also provides a signal to generate a turbine runback prior to reaching the Trip Setpoint. A turbine runback will reduce turbine power and reactor power. A reduction in power will normally alleviate the Overtemperature ΔT condition and may prevent a reactor trip.

The LCO requires all four channels of the Overtemperature ΔT trip Function to be OPERABLE. Note that the Overtemperature ΔT Function receives input from channels shared with other RPS Functions. Failures that affect multiple Functions require entry into the Conditions applicable to all affected Functions.

In MODE 1 or 2, the Overtemperature ΔT trip must be OPERABLE to prevent DNB. In MODE 3, 4, 5, or 6, this trip Function does not have to be OPERABLE because the reactor is not operating and there is insufficient heat production to be concerned about DNB.

6. <u>Overpower ΔT</u>

The Overpower ΔT trip Function ensures that protection is provided to ensure the integrity of the fuel (i.e., no fuel pellet melting and less than 1% cladding strain) under all possible overpower conditions. This trip Function also limits the required range of the Overtemperature ΔT trip Function and provides a backup to the Power Range Neutron Flux - High Setpoint trip. The Overpower ΔT trip Function ensures that the allowable heat generation rate (kW/ft) of the fuel is not exceeded. It uses the ΔT of each loop as a measure of reactor power with a setpoint that is automatically varied with the following parameters:

- reactor coolant average temperature - the Trip Setpoint is varied to correct for changes in coolant density

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

and specific heat capacity with changes in coolant temperature; and

- rate of change of reactor coolant average temperature – including a constant determined by dynamic considerations that provides compensation for the delays between the core and the temperature measurement system.

The Overpower ΔT trip Function is calculated for each loop as per Note 2 of Table 3.3.1-1. Trip occurs if Overpower ΔT is indicated in two loops. The temperature signals are used for other control functions. Therefore, the actuation logic is designed to withstand an input failure to the control system, which may then require the protection function actuation and a single failure in the remaining channels providing the protection function actuation. Note that this Function also provides a signal to generate a turbine runback prior to reaching the Allowable Value. A turbine runback will reduce turbine power and reactor power. A reduction in power will normally alleviate the Overpower ΔT condition and may prevent a reactor trip.

The LCO requires four channels of the Overpower ΔT trip Function to be OPERABLE. Note that the Overpower ΔT trip Function receives input from channels shared with other RPS Functions. Failures that affect multiple Functions require entry into the Conditions applicable to all affected Functions.

In MODE 1 or 2, the Overpower ΔT trip Function must be OPERABLE. These are the only times that enough heat is generated in the fuel to be concerned about the heat generation rates and overheating of the fuel. In MODE 3, 4, 5, or 6, this trip Function does not have to be OPERABLE because the reactor is not operating and there is insufficient heat production to be concerned about fuel overheating and fuel damage.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

7. Pressurizer Pressure

The same sensors provide input to the Pressurizer Pressure – High and – Low trips and the Overtemperature ΔT trip. The Pressurizer Pressure channels are also used to provide input to the Pressurizer Pressure Control System. Therefore, the actuation logic is designed to withstand an input failure to the control system, which may then require the protection function actuation, and a single failure in the other channels providing the protection function actuation. Note that the plant design and this LCO require 4 channels for the Pressurizer Pressure– Low trips but requires only 3 channels of Pressurizer Pressure – High. This difference recognizes the role of pressurizer code safety valves in response to a high pressure condition.

a. Pressurizer Pressure-Low

The Pressurizer Pressure – Low trip Function ensures that protection is provided against violating the DNBR limit due to low pressure.

The LCO requires four channels of Pressurizer Pressure – Low to be OPERABLE.

In MODE 1, when DNB is a major concern, the Pressurizer Pressure – Low trip must be OPERABLE. This trip Function is automatically enabled on increasing power by the P-7 interlock (NIS power range P-10 or turbine first stage pressure greater than approximately 10% of full power equivalent). On decreasing power, this trip Function is automatically blocked below P-7. Below the P-7 setpoint, no conceivable power distributions can occur that would cause DNB concerns.

b. Pressurizer Pressure-High

The Pressurizer Pressure – High trip Function ensures that protection is provided against overpressurizing

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

the RCS. This trip Function operates in conjunction with the pressurizer relief and safety valves to prevent RCS overpressure conditions.

The LCO requires three channels of the Pressurizer Pressure – High to be OPERABLE.

The Pressurizer Pressure – High Allowable Value is selected to be below the pressurizer safety valve actuation pressure and above the power operated relief valve (PORV) setting. This setting minimizes challenges to safety valves while avoiding unnecessary reactor trip for those pressure increases that can be controlled by the PORVs.

In MODE 1 or 2, the Pressurizer Pressure – High trip must be OPERABLE to help prevent RCS overpressurization and minimize challenges to the safety valves. In MODE 3, 4, 5, or 6, the Pressurizer Pressure – High trip Function does not have to be OPERABLE because transients that could cause an overpressure condition will be slow to occur. Therefore, the operator will have sufficient time to evaluate unit conditions and take corrective actions. Additionally, low temperature overpressure protection systems provide overpressure protection when RCS temperature is less than the LTOP arming temperature specified in LCO 3.4.12, Low Temperature Overpressure Protection (LTOP).

8. <u>Pressurizer Water Level-High</u>

The Pressurizer Water Level – High trip Function provides a backup signal for the Pressurizer Pressure – High trip and also provides protection against water relief through the pressurizer safety valves. These valves are designed to pass steam in order to achieve their design energy removal rate. A reactor trip is actuated prior to the pressurizer becoming water solid. The LCO requires three channels of Pressurizer Water Level – High to be OPERABLE. The

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

pressurizer level channels are used as input to the Pressurizer Level Control System. A fourth channel is not required to address control/protection interaction concerns because the level channels do not actuate the safety valves, and the high pressure reactor trip is set below the safety valve setting. Therefore, with the slow rate of charging available, pressure overshoot due to level channel failure cannot cause the safety valve to lift before reactor high pressure trip.

In MODE 1, when there is a potential for overfilling the pressurizer, the Pressurizer Water Level – High trip must be OPERABLE. This trip Function is automatically enabled on increasing power by the P-7 interlock. On decreasing power, this trip Function is automatically blocked below P-7. Below the P-7 setpoint, transients that could raise the pressurizer water level will be slow and the operator will have sufficient time to evaluate unit conditions and take corrective actions.

9. Reactor Coolant Flow-Low

a. Reactor Coolant Flow-Low (Single Loop)

The Reactor Coolant Flow – Low (Single Loop) trip Function ensures that protection is provided against violating the DNBR limit due to low flow in one or more RCS loops, while avoiding reactor trips due to normal variations in loop flow. Above the P-8 setpoint, which is approximately 50% RTP, a loss of flow in any RCS loop will actuate a reactor trip. Each RCS loop has three flow detectors to monitor flow. The flow signals are not used for any control system input.

The LCO requires three Reactor Coolant Flow – Low channels per RCS loop to be OPERABLE in MODE 1 above P-8. Each reactor coolant loop is considered to be a separate function. Therefore, separate condition entry is allowed for each loop.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

In MODE 1 above the P-8 setpoint, a loss of flow in one RCS loop could result in DNB conditions in the core. In MODE 1 below the P-8 setpoint, a loss of flow in two or more loops is required to actuate a reactor trip (Function 9.b) because of the lower power level and the greater margin to the design limit DNBR.

b. Reactor Coolant Flow-Low (Two Loops)

The Reactor Coolant Flow-Low (Two Loops) trip Function ensures that protection is provided against violating the DNBR limit due to low flow in two or more RCS loops while avoiding reactor trips due to normal variations in loop flow.

Above the P-7 setpoint and below the P-8 setpoint, a loss of flow in two or more loops will initiate a reactor trip. Each loop has three flow detectors to monitor flow. The flow signals are not used for any control system input.

The LCO requires three Reactor Coolant Flow-Low channels per loop to be OPERABLE. Each reactor coolant loop is considered to be a separate function. Therefore, separate condition entry is allowed for each loop.

In MODE 1 above the P-7 setpoint and below the P-8 setpoint, the Reactor Coolant Flow-Low (Two Loops) trip must be OPERABLE. Below the P-7 setpoint, all reactor trips on low flow are automatically blocked since no conceivable power distributions could occur that would cause a DNB concern at this low power level. Above the P-7 setpoint, the reactor trip on low flow in two or more RCS loops is automatically enabled. Above the P-8 setpoint, a loss of flow in any one loop (Function 9.a) will actuate a reactor trip because of the higher power level and the reduced margin to the design limit DNBR.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

10. Reactor Coolant Pump (RCP) Breaker Position

Both RCP Breaker Position trip Function operates to anticipate the Reactor Coolant Flow – Low trips to avoid RCS heatup that would occur before the low flow trip actuates.

a. Reactor Coolant Pump Breaker Position (Single Loop)

The RCP Breaker Position (Single Loop) trip Function ensures that protection is provided against violating the DNBR limit due to a loss of flow in one RCS loop. The position of each RCP breaker is monitored. If one RCP breaker is open above the P-8 setpoint, a reactor trip is initiated. This trip Function will generate a reactor trip before the Reactor Coolant Flow – Low (Single Loop) Trip Setpoint is reached.

The LCO requires one RCP Breaker Position channel per RCP to be OPERABLE. One OPERABLE channel is sufficient for this trip Function because the RCS Flow – Low trip alone provides sufficient protection of unit SLs for loss of flow events. The RCP Breaker Position trip serves only to anticipate the low flow trip, minimizing the thermal transient associated with loss of a pump. Each reactor coolant loop is considered to be a separate function. Therefore, separate condition entry is allowed for each loop.

This Function measures only the discrete position (open or closed) of the RCP breaker, using a position switch. Therefore, the Function has no adjustable trip setpoint with which to associate an LSSS.

In MODE 1 above the P-8 setpoint, when a loss of flow in any RCS loop could result in DNB conditions in the core, the RCP Breaker Position (Single Loop) trip must be OPERABLE. In MODE 1 below the P-8 setpoint, a loss of flow in two or more loops (Function 10.b) is required to actuate a reactor trip because of the

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

lower power level and the greater margin to the design limit DNBR.

b. Reactor Coolant Pump Breaker Position (Two Loops)

The RCP Breaker Position (Two Loops) trip Function ensures that protection is provided against violating the DNBR limit due to a loss of flow in two or more RCS loops. The position of each RCP breaker is monitored. Above the P-7 setpoint a loss of flow in two or more loops will initiate a reactor trip. This trip Function will generate a reactor trip before the Reactor Coolant Flow – Low (Two Loops) Trip Setpoint is reached.

The LCO requires one RCP Breaker Position channel per RCP to be OPERABLE. One OPERABLE channel is sufficient for this Function because the RCS Flow – Low trip alone provides sufficient protection of unit SLs for loss of flow events. The RCP Breaker Position trip serves only to anticipate the low flow trip, minimizing the thermal transient associated with loss of an RCP. Each reactor coolant loop is considered to be a separate function. Therefore, separate condition entry is allowed for each loop.

This Function measures only the discrete position (open or closed) of the RCP breaker, using a position switch. Therefore, the Function has no adjustable trip setpoint with which to associate an LSSS.

In MODE 1 above the P-7 setpoint and below the P-8 setpoint, the RCP Breaker Position (Two Loops) trip must be OPERABLE. Below the P-7 setpoint, all reactor trips on loss of flow are automatically blocked since no conceivable power distributions could occur that would cause a DNB concern at this low power level. Above the P-7 setpoint, the reactor trip on loss of flow in two RCS loops is automatically enabled. Above the P-8 setpoint, a loss of flow in any one loop

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

(Function 10.a) will actuate a reactor trip because of the higher power level and the reduced margin to the design limit DNBR.

11. Undervoltage Reactor Coolant Pumps (6.9 kV Bus)

The Undervoltage RCPs direct reactor trip Function ensures that protection is provided against violating the DNBR limit due to a loss of flow in two or more RCS loops. The voltage to each 6.9 kV bus used to power an RCP is monitored. Above the P-7 setpoint, a loss of voltage detected on two or more RCP buses will initiate a direct reactor trip. This trip Function will generate a reactor trip before the Reactor Coolant Flow - Low (Two Loops) Trip Setpoint is reached. Time delays are incorporated into the Undervoltage RCPs channels associated with the direct reactor trip and are provided to prevent reactor trips due to momentary electrical power transients.

The LCO requires one Undervoltage RCPs channel per bus to be OPERABLE.

In MODE 1 above the P-7 setpoint, the Undervoltage RCP trip must be OPERABLE. Below the P-7 setpoint, all reactor trips on loss of flow are automatically blocked since no conceivable power distributions could occur that would cause a DNB concern at this low power level. Above the P-7 setpoint, the reactor trip on loss of flow in two or more RCS loops is automatically enabled.

12. Underfrequency Reactor Coolant Pumps

The Underfrequency RCPs reactor trip Function ensures that protection is provided against violating the DNBR limit due to a loss of flow in two or more RCS loops from a major network frequency disturbance. An underfrequency condition will slow down the pumps, thereby reducing their coastdown time following a pump trip. The proper coastdown time is required so that reactor heat can be removed immediately after reactor trip. The frequency of each RCP bus is

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

monitored. A loss of frequency detected on two or more RCP buses trips all four RCPs, a condition that will initiate a reactor trip. This trip Function will generate a reactor trip before the Reactor Coolant Flow – Low (Two Loops) Trip Setpoint is reached.

The LCO requires one Underfrequency RCP channel per bus to be OPERABLE.

13. Steam Generator Water Level-Low Low

The SG Water Level – Low Low trip Function ensures that protection is provided against a loss of heat sink and actuates the AFW System prior to uncovering the SG tubes. The SGs are the heat sink for the reactor. In order to act as a heat sink, the SGs must contain a minimum amount of water. A narrow range low low level in any SG is indicative of a loss of heat sink for the reactor. The "B" channel level transmitters provide input to the SG Level Control System. This Function also performs the function of starting the AFW pumps on low low SG level.

The LCO requires three channels of SG Water Level – Low Low per SG to be OPERABLE. Each SG is considered to be a separate function. Therefore, separate condition entry is allowed for each SG.

In MODE 1 or 2, when the reactor requires a heat sink, the SG Water Level – Low Low trip must be OPERABLE. The normal source of water for the SGs is the Main Feedwater (MFW) System (not safety related). The MFW System is only in operation in MODE 1 or 2. The AFW System is the safety related backup source of water to ensure that the SGs remain the heat sink for the reactor. During normal startups and shutdowns, the AFW System provides feedwater to maintain SG level. In MODE 3, 4, 5, or 6, the SG Water Level – Low Low Function does not have to be OPERABLE because the MFW System is not in operation and the reactor is not critical. Decay heat removal is accomplished by the

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

AFW System in MODE 3 and 4 and by the Residual Heat Removal (RHR) System in MODE 4, 5, or 6.

14. Steam Generator Water Level-Low, Coincident With Steam Flow/Feedwater Flow Mismatch

SG Water Level – Low, in conjunction with the Steam Flow/Feedwater Flow Mismatch, ensures that protection is provided against a loss of heat sink and actuates the AFW System. In addition to a decreasing water level in the SG, the difference between feedwater flow and steam flow is evaluated to determine if feedwater flow is significantly less than steam flow. With less feedwater flow than steam flow, SG level will decrease at a rate dependent upon the magnitude of the difference in flow rates. The required logic is developed from two SG level channels and two Steam Flow/Feedwater Flow Mismatch channels per SG. One narrow range level channel coincident with the associated Steam Flow/Feedwater Flow Mismatch channel for the same SG (steam flow greater than feed flow) will actuate a reactor trip. This function also initiates a turbine trip if reactor power is above the P-7 setpoint.

The LCO requires two channels of SG Water Level – Low coincident with Steam Flow/Feedwater Flow Mismatch. Each SG is considered to be a separate function. Therefore, separate condition entry is allowed for each SG.

Table 3.3.1-1 identifies the Technical Specification Allowable Value for this trip function as not applicable (NA) because LCO 3.3.1, Function 13, Steam Generator Water Level-Low Low, is used to bound the analysis for a loss of feedwater event. The allowable values required for OPERABILITY of this trip function is ≥ 3.54% for steam generator level (the same allowable value as the Steam Generator Water Level-Low Low) and ≥ 1.64 E+6 pounds per hour difference for the steam flow feed flow mismatch. These allowable values are based on engineering judgement.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

In MODE 1 or 2, when the reactor requires a heat sink, the SG Water Level - Low coincident with Steam Flow/Feedwater Flow Mismatch trip must be OPERABLE. The normal source of water for the SGs is the MFW System (not safety related). The MFW System is only in operation in MODE 1 or 2. The AFW System is the safety related backup source of water to ensure that the SGs remain the heat sink for the reactor. During normal startups and shutdowns, the AFW System provides feedwater to maintain SG level. In MODE 3, 4, 5, or 6, the SG Water Level - Low coincident with Steam Flow/ Feedwater Flow Mismatch Function does not have to be OPERABLE because the MFW System is not in operation and the reactor is not critical. Decay heat removal is accomplished by the AFW System in MODE 3 and 4 and by the RHR System in MODE 4, 5, or 6. The MFW System is in operation only in MODE 1 or 2 and, therefore, this trip Function need only be OPERABLE in these MODES.

15. <u>Turbine Trip - Low Auto-Stop Oil Pressure</u>

The Turbine Trip - Low Auto-Stop Oil Pressure trip Function anticipates the loss of heat removal capabilities of the secondary system following a turbine trip. This trip Function acts to minimize the pressure/temperature transient on the reactor. Any turbine trip from a power level below the P-7 setpoint, approximately 10% power, will not actuate a reactor trip. Three pressure switches monitor the control oil pressure in the Turbine Control System. A low pressure condition sensed by two-out-of-three pressure switches will actuate a reactor trip. These pressure switches do not provide any input to the control system. The unit is designed to withstand a complete loss of load and not sustain core damage or challenge the RCS pressure limitations. Core protection is provided by the Pressurizer Pressure - High trip Function and RCS integrity is ensured by the pressurizer safety valves.

The LCO requires three channels of Turbine Trip - Low Fluid Oil Pressure to be OPERABLE in MODE 1 above P-7.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Below the P-7 setpoint, a turbine trip does not actuate a reactor trip. In MODE 1 (below P-7 setpoint), 2, 3, 4, 5, or 6, there is no potential for a turbine trip that would require a reactor trip, and the Turbine Trip – Low Auto-Stop Oil Pressure trip Function does not need to be OPERABLE.

16. <u>Safety Injection Input from Engineered Safety Feature Actuation System</u>

The SI Input from ESFAS ensures that if a reactor trip has not already been generated by the RPS, the ESFAS automatic actuation logic will initiate a reactor trip signal upon any signal that initiates SI. This is a condition of acceptability for the LOCA. However, other transients and accidents take credit for varying levels of ESF performance and rely upon rod insertion, except for the most reactive rod that is assumed to be fully withdrawn, to ensure reactor shutdown. Therefore, a reactor trip is initiated every time an SI signal is present.

Trip Setpoint and Allowable Values are not applicable to this Function. The SI Input is provided by relay in the ESFAS. Therefore, there is no measurement signal with which to associate an LSSS.

The LCO requires two trains of SI Input from ESFAS to be OPERABLE in MODE 1 or 2.

A reactor trip is initiated every time an SI signal is present. Therefore, this trip Function must be OPERABLE in MODE 1 or 2, when the reactor is critical, and must be shut down in the event of an accident. In MODE 3, 4, 5, or 6, the reactor is not critical, and this trip Function does not need to be OPERABLE.

17. <u>Reactor Trip System Interlocks</u>

Reactor protection interlocks are provided to ensure reactor trips are in the correct configuration for the current unit status. They back up operator actions to

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

ensure protection system Functions are not bypassed during unit conditions under which the safety analysis assumes the Functions are not bypassed. Therefore, the interlock Functions do not need to be OPERABLE when the associated reactor trip functions are outside the applicable MODES. These are:

a. Intermediate Range Neutron Flux, P-6

The Intermediate Range Neutron Flux, P-6 interlock is actuated when any NIS intermediate range channel goes approximately one decade above the minimum channel reading. If both channels drop below the setpoint, the permissive will automatically be defeated. Manual defeat of the P-6 interlock can be accomplished at any time by simultaneous actuation of both Reset pushbuttons. The LCO requirement for the P-6 interlock ensures that the following Functions are performed:

- on increasing power, the P-6 interlock allows the manual block of the NIS Source Range, Neutron Flux reactor trip. This prevents a premature block of the source range trip and allows the operator to ensure that the intermediate range is OPERABLE prior to leaving the source range. The source range trip is blocked by removing the high voltage to the detectors;
- on decreasing power, the P-6 interlock automatically energizes the NIS source range detectors and enables the NIS Source Range Neutron Flux reactor trip; and

The LCO requires two channels of Intermediate Range Neutron Flux, P-6 interlock to be OPERABLE in MODE 2 when below the P-6 interlock setpoint.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Above the P-6 interlock setpoint, the NIS Source Range Neutron Flux reactor trip will be blocked, and this Function will no longer be necessary.

In MODE 3, 4, 5, or 6, the P-6 interlock does not have to be OPERABLE because the NIS Source Range is providing core protection if required.

b. <u>Low Power Reactor Trips Block, P-7</u>

The Low Power Reactor Trips Block, P-7 interlock, is actuated by input from either the Power Range Neutron Flux, P-10, or the Turbine First Stage Pressure. The LCO requirement for the P-7 interlock ensures that the following Functions are performed:

(1) on increasing power, the P-7 interlock (i.e., 2 of 4 Power Range channels increasing above the P-10 (Function 17.d) setpoint or 1 of 2 Turbine First Stage Pressure (Function 17.e) setpoint) automatically enables reactor trips on the following Functions:

- Pressurizer Pressure – Low;
- Pressurizer Water Level – High;
- Reactor Coolant Flow – Low (Two Loops);
- RCPs Breaker Open (Two Loops);
- Undervoltage RCPs; and
- Turbine Trip.

These reactor trips are only required when operating above the P-7 setpoint (approximately 10% power). The reactor trips provide protection against violating the DNBR limit. Below the P-7 setpoint, the RCS is capable of

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providing sufficient natural circulation without any RCP running.

(2) on decreasing power, the P-7 interlock (i.e., 3 of 4 Power Range channels decreasing below the P-10 (Function 17.d) setpoint and 2 of 2 Turbine First Stage Pressure channels decreasing below the Turbine First Stage Pressure (Function 17.e) setpoint) automatically blocks reactor trips on the following Functions:

- Pressurizer Pressure – Low;
- Pressurizer Water Level – High;
- Reactor Coolant Flow – Low (Two Loops);
- RCP Breaker Position (Two Loops);
- Undervoltage RCPs; and
- Turbine Trip.

An Allowable Value is not applicable to the P-7 interlock because it is a logic Function. The Allowable Value for the P-10 interlock (Function 17.d) governs input from the Power Range instruments and the Allowable Value for the Turbine First Stage Pressure interlock (Function 17.e) governs input for turbine power.

The P-7 interlock is a logic Function with train and not channel identity. Therefore, the LCO requires one channel per train (i.e., two trains) of Low Power Reactor Trips Block, P-7 interlock to be OPERABLE in MODE 1.

The low power trips are blocked below the P-7 setpoint and unblocked above the P-7 setpoint. In MODE 2, 3,

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

4, 5, or 6, this Function does not have to be OPERABLE because the interlock performs its Function when power level drops below 10% power, which is in MODE 1.

c. <u>Power Range Neutron Flux, P-8</u>

The Power Range Neutron Flux, P-8 interlock is actuated at approximately 50% power as determined by NIS power range detectors. The P-8 interlock automatically enables the Reactor Coolant Flow—Low (Single Loop) and RCP Breaker Position (Single Loop) reactor trips on low flow in one or more RCS loops whenever at least 2 of 4 the Power Range instruments increase to above the P-8 setpoint. The LCO requirement for this trip Function ensures that protection is provided against a loss of flow in any RCS loop that could result in DNB conditions in the core when greater than approximately 50% power. On decreasing power, the reactor trip on low flow in any loop is automatically blocked whenever at least 3 of 4 the Power Range instruments decrease to below the P-8 setpoint.

The LCO requires four channels of Power Range Neutron Flux, P-8 interlock to be OPERABLE in MODE 1.

In MODE 1, a loss of flow in one RCS loop could result in DNB conditions, so the Power Range Neutron Flux, P-8 interlock must be OPERABLE. In MODE 2, 3, 4, 5, or 6, this Function does not have to be OPERABLE because the core is not producing sufficient power to be concerned about DNB conditions.

d. <u>Power Range Neutron Flux, P-10</u>

The Power Range Neutron Flux, P-10 interlock is actuated at approximately 10% power, as determined by two-out-of-four NIS power range detectors. If power level falls below 10% RTP on 3 of 4 channels, the nuclear instrument trips will be automatically

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

unblocked. The LCO requirement for the P-10 interlock ensures that the following Functions are performed:

- on increasing power, the P-10 interlock allows the operator to manually block the Intermediate Range Neutron Flux reactor trip;
- on increasing power, the P-10 interlock allows the operator to manually block the Power Range Neutron Flux – Low reactor trip;
- on increasing power, the P-10 interlock automatically provides a backup signal to block the Source Range Neutron Flux reactor trip by de-energizing the NIS source range detectors;
- the P-10 interlock provides one of the two inputs to the P-7 interlock; and
- on decreasing power, the P-10 interlock automatically enables the Power Range Neutron Flux – Low reactor trip and the Intermediate Range Neutron Flux reactor trip (and rod stop).

The LCO requires four channels of Power Range Neutron Flux, P-10 interlock to be OPERABLE in MODE 1 or 2.

OPERABILITY in MODE 1 ensures the Function is available to perform its decreasing power Functions in the event of a reactor shutdown. This Function must be OPERABLE in MODE 2 to ensure that core protection is provided during a startup or shutdown by the Power Range Neutron Flux – Low and Intermediate Range Neutron Flux reactor trips. In MODE 3, 4, 5, or 6, this Function does not have to be OPERABLE because the reactor is not at power and the Source Range Neutron Flux reactor trip provides core protection.

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e. Turbine First Stage Pressure

The Turbine First Stage Pressure interlock is actuated when the pressure in the first stage of the high pressure turbine is greater than approximately 10% of the rated full power pressure. This is determined by one-out-of-two pressure detectors. The LCO requirement for this Function ensures that one of the inputs to the P-7 interlock is available.

The LCO requires two channels of Turbine Impulse Pressure, input to the P-7 interlock, to be OPERABLE in MODE 1.

The Turbine First Stage Pressure interlock must be OPERABLE when the turbine generator is operating. The interlock Function is not required OPERABLE in MODE 2, 3, 4, 5, or 6 because the turbine generator is not operating.

18. Reactor Trip Breakers

This trip Function applies to the RTBs exclusive of individual trip mechanisms. The LCO requires two OPERABLE trains of trip breakers. A trip breaker train consists of all trip breakers associated with a single RPS logic train that are racked in, closed, and capable of supplying power to the Rod Control System. Thus, the train may consist of the main breaker, bypass breaker, or main breaker and bypass breaker, depending upon the system configuration. Two OPERABLE trains ensure no single random failure can disable the RPS trip capability.

The LCO requires two OPERABLE trains of trip breakers. Two OPERABLE trains ensure no single random failure can disable the RPS trip capability. When a reactor trip breaker is being tested, both reactor trip breaker and the reactor trip bypass breaker associated with the RPS

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

logic train not in test are closed. In this configuration, a single failure in the RPS logic train not in test could disable RPS trip capability; therefore, limits on the duration of testing are established.

These trip Functions must be OPERABLE in MODE 1 or 2 when the reactor is critical. In MODE 3, 4, or 5, these RPS trip Functions must be OPERABLE when the Rod Control System is capable of rod withdrawal and one or more rods are not fully inserted.

19. Reactor Trip Breaker Undervoltage and Shunt Trip Mechanisms

The LCO requires both the Undervoltage and Shunt Trip Mechanisms to be OPERABLE for each RTB that is in service. The trip mechanisms are not required to be OPERABLE for trip breakers that are open, racked out, incapable of supplying power to the Rod Control System, or declared inoperable under Function 18 above. OPERABILITY of both trip mechanisms on each breaker ensures that no single trip mechanism failure will prevent opening any breaker on a valid signal.

These trip Functions must be OPERABLE in MODE 1 or 2 when the reactor is critical. In MODE 3, 4, or 5, these RPS trip Functions must be OPERABLE when the Rod Control System is capable of rod withdrawal and one or more rods are not fully inserted.

20. Automatic Trip Logic

The LCO requirement for the RTBs (Functions 18 and 19) and Automatic Trip Logic (Function 20) ensures that means are provided to interrupt the power to allow the rods to fall into the reactor core. Each RTB is equipped with a bypass breaker (RTBB) to allow testing of the trip breaker while the unit is at power. Each RTB and RTBB is equipped with

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an undervoltage coil and a shunt trip coil to trip the breaker open when needed. The reactor trip signals generated by the RPS Automatic Trip Logic cause the RTBs and associated bypass breakers to open and shut down the reactor.

The LCO requires two trains of RPS Automatic Trip Logic to be OPERABLE. Having two OPERABLE channels ensures that random failure of a single logic channel will not prevent reactor trip.

These trip Functions must be OPERABLE in MODE 1 or 2 when the reactor is critical. In MODE 3, 4, or 5, these RPS trip Functions must be OPERABLE when the Rod Control System is capable of rod withdrawal and one or more rods are not fully inserted.

The RPS instrumentation satisfies Criterion 3 of 10 CFR 50.36.

ACTIONS

Note 1 has been added to the ACTIONS to clarify the application of Completion Time rules. The Conditions of this Specification may be entered independently for each Function listed in Table 3.3.1-1.

Note 2 specifies that when a channel or train is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 8 hours, provided the associated Function(s) maintains RPS trip capability. Upon completion of the Surveillance, or expiration of the 8 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is consistent with the assumptions of the instrumentation system reliability analysis (Ref. 7). That analysis demonstrated that the 8 hour testing allowance does not significantly reduce the probability that the RPS will trip when necessary.

BASES

ACTIONS (continued)

As noted in Reference 9, the allowance of 2 hours for test and maintenance of reactor trip breakers provided in Condition L, Note 1, is less than the 6 hour allowable out of service time and the 8 hour allowance for testing of RPS train A and train B. In practice, if the reactor trip breaker is being tested at the same time as the associated logic train, the 8 hour allowance for testing of RPS train A and train B applies to both the logic train and the reactor trip breaker. This is acceptable based on the Safety Evaluation Report for Reference 7.

In the event a channel's Trip Setpoint is found nonconservative with respect to the Allowable Value, or the transmitter, instrument loop, signal processing electronics, or bistable is found inoperable, then all affected Functions provided by that channel must be declared inoperable and the LCO Condition(s) entered for the protection Function(s) affected.

When the number of inoperable channels in a trip Function exceed those specified in one or other related Conditions associated with a trip Function, then the unit is outside the safety analysis. Therefore, LCO 3.0.3 must be immediately entered if applicable in the current MODE of operation.

A.1

Condition A applies to all RPS protection Functions. Condition A addresses the situation where one or more required channels or trains for one or more Functions are inoperable at the same time. The Required Action is to refer to Table 3.3.1-1 and to take the Required Actions for the protection functions affected. The Completion Times are those from the referenced Conditions and Required Actions.

B.1 and B.2

Condition B applies to the Manual Reactor Trip in MODE 1 or 2. This action addresses the train orientation of the relay logic for this Function. With one channel inoperable, the inoperable channel must be restored to OPERABLE status within 48 hours. In

BASES

ACTIONS

B.1 and B.2 (continued)

this Condition, the remaining OPERABLE channel is adequate to perform the safety function.

The Completion Time of 48 hours is reasonable considering that there are two automatic actuation trains and another manual initiation channel OPERABLE, and the low probability of an event occurring during this interval.

If the Manual Reactor Trip Function cannot be restored to OPERABLE status within the allowed 48 hour Completion Time, the unit must be brought to a MODE in which the requirement does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 additional hours (54 hours total time). The 6 additional hours to reach MODE 3 is reasonable, based on operating experience, to reach MODE 3 from full power operation in an orderly manner and without challenging unit systems. With the unit in MODE 3, ACTION C applies to any inoperable Manual Reactor Trip Function if the Rod Control System is capable of rod withdrawal and one or more rods are not fully inserted.

C.1 and C.2

Condition C applies to the following reactor trip Functions in MODE 3, 4, or 5 when the Rod Control System capable of rod withdrawal and one or more rods are not fully inserted:

- Manual Reactor Trip;
- RTBs;
- RTB Undervoltage and Shunt Trip Mechanisms; and
- Automatic Trip Logic.

This action addresses the train orientation of the relay logic for these Functions. With one channel or train inoperable, the inoperable channel or train must be restored to OPERABLE status within 48 hours. If the affected Function(s) cannot be restored to OPERABLE status within the allowed 48 hour Completion Time, the unit must be placed in a MODE in which the requirement does

BASES

ACTIONS

C.1 and C.2 (continued)

not apply. To achieve this status, action must be initiated within the same 48 hours to ensure that all rods are fully inserted, and the Rod Control System must be placed in a condition incapable of rod withdrawal within the next hour. The additional hour provides sufficient time to accomplish the action in an orderly manner. With rods fully inserted and the Rod Control System incapable of rod withdrawal, these Functions are no longer required.

The Completion Time is reasonable considering that in this Condition, the remaining OPERABLE train is adequate to perform the safety function, and given the low probability of an event occurring during this interval.

D.1.1, D.1.2, D.2.1, D.2.2, and D.3

Condition D applies to the Power Range Neutron Flux—High Function.

The NIS power range detectors provide input to the Rod Control System and, therefore, have a two-out-of-four trip logic. A known inoperable channel must be placed in the tripped condition. This results in a partial trip condition requiring only one-out-of-three logic for actuation. The 6 hours allowed to place the inoperable channel in the tripped condition is justified in WCAP-10271-P-A (Ref. 7).

In addition to placing the inoperable channel in the tripped condition, THERMAL POWER must be reduced to ≤ 75% RTP within 24 hours. Reducing the power level prevents operation of the core with radial power distributions beyond the design limits. With one of the NIS power range detectors inoperable, 1/4 of the radial power distribution monitoring capability is lost.

As an alternative to the above actions, the inoperable channel can be placed in the tripped condition within 6 hours and the QPTR monitored once every 24 hours as per SR 3.2.4.2, QPTR verification. Calculating QPTR every 24 hours compensates for the lost monitoring capability due to the inoperable NIS power range channel and allows continued unit operation at power levels

BASES

ACTIONS

D.1.1, D.1.2, D.2.1, D.2.2, and D.3 (continued)

≥ 75% RTP. The 6 hour Completion Time and the 24 hour Frequency are consistent with LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)."

As an alternative to the above Actions, the plant must be placed in a MODE where this Function is no longer required OPERABLE. Twelve hours are allowed to place the plant in MODE 3. This is a reasonable time, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging plant systems. If Required Actions cannot be completed within their allowed Completion Times, LCO 3.0.3 must be entered.

The Required Actions have been modified by a Note that allows placing the inoperable channel in the bypass condition for up to 8 hours while performing routine surveillance testing of other channels. The Note also allows placing the inoperable channel in the bypass condition to allow setpoint adjustments of other channels when required to reduce the setpoint in accordance with other Technical Specifications. The 8 hour time limit is justified in Reference 7.

Required Action D.2.2 has been modified by a Note which only requires SR 3.2.4.2 to be performed if the Power Range Neutron Flux input to QPTR becomes inoperable. Failure of a component in the Power Range Neutron Flux Channel which renders the High Flux Trip Function inoperable may not affect the capability to monitor QPTR. As such, determining QPTR using this movable incore detectors once per 24 hours may not be necessary.

E.1 and E.2

Condition E applies to the following reactor trip Functions:

- Power Range Neutron Flux – Low;
- Overtemperature ΔT;
- Overpower ΔT;
- Pressurizer Pressure – High;

BASES

ACTIONS

E.1 and E.2 (continued)

- SG Water Level – Low Low; and
- SG Water Level – Low coincident with Steam Flow/Feedwater Flow Mismatch.

A known inoperable channel must be placed in the tripped condition within 6 hours. Placing the channel in the tripped condition results in a partial trip condition requiring only one-out-of-two logic for actuation of the two-out-of-three trips and one-out-of-three logic for actuation of the two-out-of-four trips. The 6 hours allowed to place the inoperable channel in the tripped condition is justified in Reference 7.

If the operable channel cannot be placed in the trip condition within the specified Completion Time, the unit must be placed in a MODE where these Functions are not required OPERABLE. An additional 6 hours is allowed to place the unit in MODE 3. Six hours is a reasonable time, based on operating experience, to place the unit in MODE 3 from full power in an orderly manner and without challenging unit systems.

The Required Actions have been modified by a Note that allows placing the inoperable channel in the bypassed condition for up to 8 hours while performing routine surveillance testing of the other channels. The 8 hour time limit is justified in Reference 7.

F.1 and F.2

Condition F applies when there are no Intermediate Range Neutron Flux trip channels OPERABLE in MODE 2 when THERMAL POWER is above the P-6 setpoint and below the P-10 setpoint. Required Actions specified in this Condition are only applicable when channel failures do not result in reactor trip. Above the P-6 setpoint and below the P-10 setpoint, the NIS intermediate range detector performs the monitoring Functions. With no intermediate range channels OPERABLE, the Required Actions are to suspend operations involving positive reactivity additions immediately. This will preclude any power level increase since there are no OPERABLE Intermediate Range Neutron Flux channels. The operator must also

BASES

ACTIONS

F.1 and F.2 (continued)

reduce THERMAL POWER below the P-6 setpoint within two hours. Below P-6, one or both Source Range Neutron Flux channels will be able to monitor the core power level. The Completion Time of 2 hours will allow a slow and controlled power reduction to less than the P-6 setpoint and takes into account the low probability of occurrence of an event during this period that may require the protection afforded by the NIS Intermediate Range Neutron Flux trip.

G.1

Condition G applies when there are no Source Range Neutron Flux trip channels OPERABLE when in MODE 2, below the P-6 setpoint, and in MODE 3, 4, or 5 with the Rod Control capable of rod withdrawal and one or more rods not rods fully inserted. With the unit in this Condition, below P-6, the NIS source range performs the monitoring and protection functions. With both source range channels inoperable, the RTBs must be opened immediately.

H.1 and H.2

Condition H applies to the following reactor trip Functions:

- Pressurizer Pressure – Low;
- Pressurizer Water Level – High;
- Reactor Coolant Flow – Low;
- RCP Breaker Position (Two Loops);
- Undervoltage RCPs; and
- Underfrequency RCPs.

With one channel inoperable, the inoperable channel must be placed in the tripped condition within 6 hours. Placing the channel in the tripped condition results in a partial trip condition requiring only one additional channel to initiate a

BASES

ACTIONS

H.1 and H.2 (continued)

reactor trip above the P-7 setpoint for the two loop function and above the P-8 setpoint for the single loop function. These Functions do not have to be OPERABLE below the P-7 setpoint because there are no loss of flow trips below the P-7 setpoint. The 6 hours allowed to place the channel in the tripped condition is justified in Reference 7. An additional 6 hours is allowed to reduce THERMAL POWER to below P-7 if the inoperable channel cannot be restored to OPERABLE status or placed in trip within the specified Completion Time. The Reactor Coolant Flow-Low (Single Loop) reactor trip does not have to be OPERABLE below the P-8 setpoint; however, the Required Action must take the plant below the P-7 setpoint if the inoperable channel is not tripped within 6 hour because of the shared components between this function and the Reactor Coolant Flow-Low (Two Loop) reactor trip function.

Allowance of this time interval takes into consideration the redundant capability provided by the remaining redundant OPERABLE channel, and the low probability of occurrence of an event during this period that may require the protection afforded by the Functions associated with Condition H.

The Required Actions have been modified by a Note that allows placing the inoperable channel in the bypassed condition for up to 8 hours while performing routine surveillance testing of the other channels. The 8 hour time limit is justified in Reference 7.

I.1 and I.2

Condition I applies to the RCP Breaker Position (Single Loop) reactor trip Function. There is one breaker position device per RCP breaker. With one channel inoperable, the inoperable channel must be restored to OPERABLE status within 6 hours. If the channel cannot be restored to OPERABLE status within the 6 hours, then THERMAL POWER must be reduced below the P-8 setpoint within the next 4 hours.

This places the unit in a MODE where the LCO is no longer applicable. This Function does not have to be OPERABLE below the

BASES

ACTIONS

I.1 and I.2 (continued)

P-8 setpoint because other RPS Functions provide core protection below the P-8 setpoint. The 6 hours allowed to restore the channel to OPERABLE status and the 4 additional hours allowed to reduce THERMAL POWER to below the P-8 setpoint are justified in Reference 7.

The Required Actions have been modified by a Note that allows placing the inoperable channel in the bypassed condition for up to 8 hours while performing routine surveillance testing of the other channels. The 8 hour time limit is justified in Reference 7.

J.1 and J.2

Condition J applies to Turbine Trip on Low Auto-Stop Oil Pressure. With one channel inoperable, the inoperable channel must be placed in the trip condition within 6 hours. If placed in the tripped condition, this results in a partial trip condition requiring only one additional channel to initiate a reactor trip. If the channel cannot be restored to OPERABLE status or placed in the trip condition, then power must be reduced below the P-7 setpoint within the next 6 hours. The 6 hours allowed to place the inoperable channel in the tripped condition and the 6 hours allowed for reducing power are justified in Reference 7.

The Required Actions have been modified by a Note that allows placing the inoperable channel in the bypassed condition for up to 8 hours while performing routine surveillance testing of the other channels. The 8 hour time limit is justified in Reference 7.

K.1 and K.2

Condition K applies to the SI Input from ESFAS reactor trip and the RPS Automatic Trip Logic in MODES 1 and 2. These actions address the train orientation of the RPS for these Functions. With one train inoperable, 6 hours are allowed to restore the train to OPERABLE status (Required Action K.1) or the unit must be placed in MODE 3 within the next 6 hours. The Completion Time

ACTIONS

K.1 and K.2 (continued)

of 6 hours (Required Action K.1) is reasonable considering that in this Condition, the remaining OPERABLE train is adequate to perform the safety function and given the low probability of an event during this interval. The Completion Time of 6 hours (Required Action K.2) is reasonable, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging unit systems.

The Required Actions have been modified by a Note that allows bypassing one train up to 8 hours for surveillance testing, provided the other train is OPERABLE.

L.1 and L.2

Condition L applies to the RTBs in MODES 1 and 2. These actions address the train orientation of the RPS for the RTBs. With one train inoperable, 1 hour is allowed to restore the train to OPERABLE status or the unit must be placed in MODE 3 within the next 6 hours. The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging unit systems. The 1 hour and 6 hour Completion Times are equal to the time allowed by LCO 3.0.3 for shutdown actions in the event of a complete loss of RPS Function. Placing the unit in MODE 3 results in ACTION C entry while RTB(s) are inoperable.

The Required Actions have been modified by two Notes. Note 1 allows one channel to be bypassed for up to 2 hours for surveillance testing, provided the other channel is OPERABLE. Note 2 allows one RTB to be bypassed for up to 2 hours for maintenance on undervoltage or shunt trip mechanisms if the other RTB train is OPERABLE. The 2 hour time limit is justified in Reference 7.

M.1 and M.2

Condition M applies to the P-6 and P-10 interlocks. With one or more channels inoperable for one-out-of-two or two-out-of-four coincidence logic, the associated interlock must be verified to be in its required state for the existing unit condition within

BASES

ACTIONS

M.1 and M.2 (continued)

1 hour or the unit must be placed in MODE 3 within the next 6 hours. Verifying the interlock status manually accomplishes the interlock's Function. The Completion Time of 1 hour is based on operating experience and the minimum amount of time allowed for manual operator actions. The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging unit systems. The 1 hour and 6 hour Completion Times are equal to the time allowed by LCO 3.0.3 for shutdown actions in the event of a complete loss of RPS Function.

N.1 and N.2

Condition N applies to the P-7 and P-8 interlocks and the turbine first stage pressure input to P-7. With one or more channels inoperable for one-out-of-two or two-out-of-four coincidence logic, the associated interlock must be verified to be in its required state for the existing unit condition within 1 hour or the unit must be placed in MODE 2 within the next 6 hours. These actions are conservative for the case where power level is being raised. Verifying the interlock status manually accomplishes the interlock's Function. The Completion Time of 1 hour is based on operating experience and the minimum amount of time allowed for manual operator actions. The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 2 from full power in an orderly manner and without challenging unit systems.

O.1 and O.2

Condition O applies to the RTB Undervoltage and Shunt Trip Mechanisms, or diverse trip features, in MODES 1 and 2. With one of the diverse trip features inoperable, it must be restored to an OPERABLE status within 48 hours or the unit must be placed in a MODE where the requirement does not apply. This is accomplished by placing the unit in MODE 3 within the next 6 hours (54 hours total time). The Completion Time of 6 hours is a reasonable time, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging unit systems.

BASES

ACTIONS

0.1 and 0.2 (continued)

With the unit in MODE 3, ACTION C applies to any inoperable RTB trip mechanism. The affected RTB shall not be bypassed while one of the diverse features is inoperable except for the time required to perform maintenance or testing to one of the diverse features. The allowable time for performing maintenance of the diverse features is 2 hours for the reasons stated under Condition L.

The Completion Time of 48 hours for Required Action 0.1 is reasonable considering that in this Condition there is one remaining diverse feature for the affected RTB, and one OPERABLE RTB capable of performing the safety function and given the low probability of an event occurring during this interval.

SURVEILLANCE REQUIREMENTS

The SRs for each RPS Function are identified by the SRs column of Table 3.3.1-1 for that Function.

A Note has been added to the SR Table stating that Table 3.3.1-1 determines which SRs apply to which RPS Functions.

Note that each channel of process protection supplies both train A and train B of the RPS. When testing an individual channel, the SR is not met until both train A and train B logic are tested. The CHANNEL CALIBRATION and COTs are performed in a manner that is consistent with the assumptions used in analytically calculating the required channel accuracies.

SR 3.3.1.1

Performance of the CHANNEL CHECK once every 12 hours ensures that gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the two instrument channels could be an

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.1 (continued)

indication of excessive instrument drift in one of the channels or of something more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying that the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the unit staff based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the sensor or the signal processing equipment has drifted outside its limit.

The Frequency is based on operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal checks of channels during normal operational use of the displays associated with the LCO required channels.

SR 3.3.1.2

SR 3.3.1.2 compares the calorimetric heat balance calculation to the NIS channel output every 24 hours. If the calorimetric exceeds the NIS channel output by > 2% RTP, the NIS is not declared inoperable, but must be adjusted. If the NIS channel output cannot be properly adjusted, the channel is declared inoperable.

Two Notes modify SR 3.3.1.2. The first Note indicates that the NIS channel output shall be adjusted consistent with the calorimetric results if the absolute difference between the NIS channel output and the calorimetric is > 2% RTP. The second Note clarifies that this Surveillance is required only if reactor power is ≥ 15% RTP and that 24 hours is allowed for performing the first Surveillance after reaching 15% RTP. At lower power levels, calorimetric data are inaccurate.

The Frequency of every 24 hours is adequate. It is based on unit operating experience, considering instrument reliability and operating history data for instrument drift. Together these

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SURVEILLANCE REQUIREMENTS

SR 3.3.1.2 (continued)

factors demonstrate the change in the absolute difference between NIS and heat balance calculated powers rarely exceeds 2% in any 24 hour period.

In addition, control room operators periodically monitor redundant indications and alarms to detect deviations in channel outputs.

SR 3.3.1.3

SR 3.3.1.3 compares the incore system to the NIS channel output every 31 EFPD. If the absolute difference is ≥ 3%, the NIS channel is still OPERABLE, but must be readjusted.

If the NIS channel cannot be properly readjusted, the channel is declared inoperable. This Surveillance is performed to verify the f(ΔI) input to the overtemperature ΔT Function.

Two Notes modify SR 3.3.1.3. Note 1 indicates that the excore NIS channel shall be adjusted if the absolute difference between the incore and excore AFD is ≥ 3%. Note 2 clarifies that the Surveillance is required only if reactor power is ≥ 90% because the requirements of LCO 3.2.3, Axial Flux Difference (AFD), are relaxed significantly below 90% RTP.

The Frequency of every 31 EFPD is adequate. It is based on unit operating experience, considering instrument reliability and operating history data for instrument drift. Also, the slow changes in neutron flux during the fuel cycle can be detected during this interval.

SR 3.3.1.4

SR 3.3.1.4 is the performance of a TADOT every 31 days on a STAGGERED TEST BASIS. This test shall verify OPERABILITY by actuation of the end devices.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.4 (continued)

The RTB test shall include separate verification of the undervoltage and shunt trip mechanisms. Independent verification of RTB undervoltage and shunt trip Function is not required for the bypass breakers. No capability is provided for performing such a test at power. The independent test of the undervoltage and shunt trip function for bypass breakers is included in SR 3.3.1.14. The bypass breaker test shall include a local shunt trip. A Note has been added to indicate that this test must be performed on the bypass breaker prior to placing it in service.

The Frequency of every 31 days on a STAGGERED TEST BASIS is adequate. It is based on industry operating experience, considering instrument reliability and operating history data.

SR 3.3.1.5

SR 3.3.1.5 is the performance of an ACTUATION LOGIC TEST. The RPS relay logic is tested every 31 days on a STAGGERED TEST BASIS. The train being tested is placed in the bypass condition, thus preventing inadvertent actuation. All possible logic combinations, with and without applicable permissives, are tested for each protection function required by Table 3.31-1. The Frequency of every 31 days on a STAGGERED TEST BASIS is adequate. It is based on industry operating experience, considering instrument reliability and operating history data.

SR 3.3.1.6

SR 3.3.1.6 is a calibration of the excore channels to the incore channels. If the measurements do not agree, the excore channels are not declared inoperable but must be calibrated to agree with the incore detector measurements. If the excore channels cannot be adjusted, the channels are declared inoperable. This Surveillance is performed to verify the $f(\Delta I)$ input to the overtemperature ΔT Function.

A Note modifies SR 3.3.1.6. The Note states that this Surveillance is required only if reactor power is > 90% because

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SURVEILLANCE REQUIREMENTS

SR 3.3.1.6 (continued)

the requirements of LCO 3.2.3, Axial Flux Difference (AFD), are relaxed significantly below 90% RTP.

The Frequency of 31 EFPD is adequate based on operating experience, considering instrument reliability and operating history data for instrument drift.

SR 3.3.1.7

SR 3.3.1.7 is the performance of a COT every 92 days.

A COT is performed on each required channel to ensure the entire channel will perform the intended Function.

Setpoints must be within the Allowable Values specified in Table 3.3.1-1.

The "as found" and "as left" values must also be recorded and reviewed. The difference between the current "as found" values and the previous test "as left" values must be consistent with the drift allowance used in the setpoint methodology. The setpoint shall be left set consistent with the assumptions of Reference 6 which incorporates the requirements of Reference 7.

SR 3.3.1.7 is modified by a Note that provides an 8 hour delay in the requirement to perform this Surveillance for source range instrumentation when entering MODE 3 from MODE 2. This Note allows a normal shutdown to proceed without a delay for testing in MODE 2 and for 8 hours in MODE 3 until the RTBs are open and SR 3.3.1.7 is no longer required to be performed. If the unit is to be in MODE 3 with the RTBs closed for > 8 hours this Surveillance must be performed prior to 8 hours after entry into MODE 3. The 8 hour deferral is needed because the testing required by SR 3.3.1.7 and SR 3.3.1.8 cannot be performed on the Source Range, Intermediate Range, and Power Range instruments until in the Applicable Mode and the proximity of these instruments prevents working on more than one instrument at any one time.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.7 (continued)

The Frequency of 92 days is justified in Reference 7.

SR 3.3.1.8

SR 3.3.1.8 is the performance of a COT as described in SR 3.3.1.7, except it is modified by a Note that this test shall include verification that the P-6 and P-10 interlocks are in their required state for the existing unit condition. The Frequency is modified by a Note that allows this surveillance to be satisfied if it has been performed within 92 days of the Frequencies prior to reactor startup and 16 hours after reducing power below P-10 and 8 hours after reducing power below P-6. The Frequency of "prior to startup" ensures this surveillance is performed prior to critical operations and applies to the source, intermediate and power range low instrument channels. The Frequency of "16 hours after reducing power below P-10" (applicable to intermediate and power range low channels) and "8 hours after reducing power below P-6" (applicable to source range channels) allows a normal shutdown to be completed and the unit removed from the MODE of Applicability for this surveillance without a delay to perform the testing required by this surveillance. The Frequency of every 92 days thereafter applies if the plant remains in the MODE of Applicability after the initial performances of prior to reactor startup. Additionally, this SR must be completed for the intermediate and power range low channels within 16 hours after reducing power below the P-10 setpoint and must be completed for the source range low channel within 8 hours after reducing power below the P-6 setpoint. The MODE of Applicability for this surveillance is < P-10 for the power range low and intermediate range channels and < P-6 for the source range channels. Once the unit is in MODE 3, this surveillance is no longer required. If power is to be maintained < P-10 or < P-6 for more than 8 hours, then the testing required by this surveillance must be performed prior to the expiration of the 8 and 16 hour limits. The specified Frequency provides a reasonable time to complete the required testing or place the unit in a MODE where this surveillance is no longer required.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.8 (continued)

This test ensures that the NIS source, intermediate, and power range low channels are OPERABLE prior to taking the reactor critical and within a reasonable time after reducing power into the applicable MODE (< P-10 or < P-6). The deferral of the requirement to perform this test until 8 or 16 hours after entering the Applicable condition is needed because the testing required by SR 3.3.1.7 and SR 3.3.1.8 cannot be performed on the Source Range, Intermediate Range, and Power Range instruments until in the Applicable Mode and the proximity of these instruments prevents working on more than one instrument at any one time.

SR 3.3.1.9

SR 3.3.1.9 is the performance of a TADOT and is performed every 92 days, as justified in Reference 7.

The SR is modified by a Note that excludes verification of setpoints from the TADOT. Since this SR applies to RCP undervoltage and underfrequency relays, setpoint verification requires elaborate bench calibration and is accomplished during the CHANNEL CALIBRATION.

SR 3.3.1.10

A CHANNEL CALIBRATION is performed at every refueling and every 18 months for function 11. CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to a measured parameter within the necessary range and accuracy.

CHANNEL CALIBRATIONS must be performed consistent with the assumptions used in Reference 6. The difference between the current "as found" values and the previous test "as left" values must be consistent with the drift allowance used in the setpoint methodology.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.10 (continued)

The Frequency is based on the calibration interval used for the determination of the magnitude of equipment drift in the setpoint methodology.

SR 3.3.1.10 is modified by a Note stating that this test shall include verification that the time constants are adjusted to the prescribed values where applicable.

SR 3.3.1.11

SR 3.3.1.11 is the performance of a CHANNEL CALIBRATION, as described in SR 3.3.1.10, every 24 months. This SR is modified by a Note stating that neutron detectors are excluded from the CHANNEL CALIBRATION. This is needed because the CHANNEL CALIBRATION for the power range neutron detectors consists of a normalization of the detectors based on a power calorimetric and flux map performed above 15% RTP. The CHANNEL CALIBRATION for the source range and intermediate range neutron detectors consists of obtaining the detector plateau or preamp discriminator curves, evaluating those curves, and comparing the curves to the manufacturer's data.

This Surveillance is not required for the NIS power range detectors for entry into MODE 2 or 1, and is not required for the NIS intermediate range detectors for entry into MODE 2, because the unit must be in at least MODE 2 to perform the test for the intermediate range detectors and MODE 1 for the power range detectors. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed on the 24 month Frequency.

SR 3.3.1.12

SR 3.3.1.12 is the performance of a CHANNEL CALIBRATION, as described in SR 3.3.1.10, every 24 months. This SR is modified

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SURVEILLANCE REQUIREMENTS

SR 3.3.1.12 (continued)

by a Note stating that this test shall include verification of the rate lag compensation for flow from the core to the RTDs. Whenever a sensing element is replaced, the next required CHANNEL CALIBRATION of resistance temperature detectors (RTD) sensors, which may consist of an inplace qualitative assessment of sensor behavior and normal calibration of the remaining adjustable devices in the channel, is accomplished by an inplace cross calibration that compares the other sensing elements with the recently installed element.

The Frequency is justified by the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.1.13

SR 3.3.1.13 is the performance of a COT of RPS interlocks every 24 months.

The Frequency is based on the known reliability of the interlocks and the multichannel redundancy available, and has been shown to be acceptable through operating experience.

SR 3.3.1.14

SR 3.3.1.14 is the performance of a TADOT of the Manual Reactor Trip, RCP Breaker Position, and the SI Input from ESFAS. This TADOT is performed every 24 months. The test shall verify the OPERABILITY of the undervoltage and shunt trip mechanisms for the Manual Reactor Trip Function for the Reactor Trip Breakers and Reactor Trip Bypass Breakers. The Reactor Trip Bypass Breaker test shall include testing of the automatic undervoltage trip.

The Frequency is based on the known reliability of the Functions and the multichannel redundancy available, and has been shown to be acceptable through operating experience.

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SURVEILLANCE REQUIREMENTS

SR 3.3.1.14 (continued)

The SR is modified by a Note that excludes verification of setpoints from the TADOT. The Functions affected have no setpoints associated with them.

SR 3.3.1.15

SR 3.3.1.15 is the performance every 24 months of a TADOT of Turbine Trip Functions. This TADOT is as described in SR 3.3.1.4. Performance of this test will ensure that the turbine trip Function is OPERABLE prior to taking the reactor critical. This test cannot be performed with the reactor at power.

REFERENCES

1. FSAR, Chapter 7.
2. FSAR, Chapter 6.
3. FSAR, Chapter 14.
4. IEEE-279-1968
5. 10 CFR 50.49.
6. Engineering Standards Manual IES-3 and IES-3B, Instrument Loop Accuracy and Setpoint Calculation Methodology (IP3).
7. WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990.
8. Consolidated Edison Company of New York, Inc. Indian Point Nuclear Generating Station Unit No. 3 Plant Manual Volume VI: Precautions, Limitations, and Setpoints, March 1975.
9. WCAP-14384, Implementation of RPS Technical Specification Relaxation Programs, Rev. 0, January 1996.

B 3.3 INSTRUMENTATION

B 3.3.2 Engineered Safety Feature Actuation System (ESFAS) Instrumentation

BASES

BACKGROUND

The ESFAS initiates necessary safety systems, based on the values of selected unit parameters, to protect against violating core design limits and the Reactor Coolant System (RCS) pressure boundary, and to mitigate accidents.

The ESFAS instrumentation is segmented into three distinct but interconnected modules as identified below:

- Field transmitters or process sensors and instrumentation: provide a measurable electronic signal based on the physical characteristics of the parameter being measured;

- Signal processing equipment including analog protection system, field contacts, and protection channel sets: provide signal conditioning, bistable setpoint comparison, process algorithm actuation, compatible electrical signal output to protection system devices, and control board/ control room/miscellaneous indications; and

- ESFAS automatic initiation relay logic: initiates the proper engineered safety feature (ESF) actuation in accordance with the defined logic and based on the bistable outputs from the signal process control and protection system.

Field Transmitters or Sensors

To meet the design demands for redundancy and reliability, more than one, and often as many as four, field transmitters or sensors are used to measure unit parameters. In many cases, field transmitters or sensors that input to the ESFAS are shared with the Reactor Protection System (RPS). In some cases, the same channels also provide control system inputs. To account for calibration tolerances and instrument drift, which are assumed to occur between calibrations, statistical allowances are provided in the Trip Setpoint and Allowable Values. The OPERABILITY of each transmitter or sensor can be evaluated when its "as found"

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BACKGROUND (Continued)

calibration data are compared against its documented acceptance criteria.

Signal Processing Equipment

Generally, three or four channels of process control equipment are used for the signal processing of unit parameters measured by the field instruments. The process control equipment provides signal conditioning, comparable output signals for instruments located on the main control board, and comparison of measured input signals with setpoints established by safety analyses. These setpoints are defined in FSAR, Chapter 6 (Ref. 1), Chapter 7 (Ref. 2), and Chapter 14 (Ref. 3). If the measured value of a unit parameter exceeds the predetermined setpoint, an output from a bistable is forwarded to the ESFAS relay logic for decision evaluation. Channel separation is maintained up to and through the input bays. However, not all unit parameters require four channels of sensor measurement and signal processing. Some unit parameters provide input only to the ESFAS relay logic, while others provide input to the ESFAS relay logic, the main control board, the unit computer, and one or more control systems.

Generally, if a parameter is used for input to the protection circuits only, three channels with a two-out-of-three logic are sufficient to provide the required reliability and redundancy. If one channel fails in a direction that would not result in a partial Function trip, the Function is still OPERABLE with a two-out-of-two logic. If one channel fails such that a partial Function trip occurs, a trip will not occur and the Function is still OPERABLE with a one-out-of- two logic.

Generally, if a parameter is used for input to the ESFAS relay logic and a control function, four channels with a two-out-of-four logic are sufficient to provide the required reliability and redundancy. The circuit is designed to withstand both an input failure to the control system, which may then require the protection function actuation, and a single failure in the other channels providing the protection function

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actuation. Again, a single failure will neither cause nor prevent the protection function actuation.

These requirements are described in IEEE-279-1968 (Ref. 4). The actual number of channels required for each unit parameter is specified in Reference 2 and discussed later in these Technical Specification Bases.

Trip Setpoints and Allowable Values

The following describes the relationship between the safety limit, analytical limit, allowable value and channel component calibration acceptance criteria:

a. A Safety Limit (SL) is a limit on the combination of THERMAL POWER, RCS highest loop average temperature, and RCS pressure needed to protect the integrity of physical barriers that guard against the uncontrolled release of radioactivity (i.e., fuel, fuel cladding, RCS pressure boundary and containment). The safety limits are identified in Technical Specification 2.0, Safety Limits (SLs).

b. An Analytical Limit (AL) is the trip actuation point used as an input to the accident analyses presented in FSAR, Chapter 14 (Ref. 3). Analytical limits are developed from event analyses models which consider parameters such as process delays, rod insertion times, reactivity changes, instrument response times, etc. An analytical limit for a trip actuation point is established at a point that will ensure that a Safety Limit (SL) is not exceeded.

c. An Allowable Value (AV) is the limiting actuation point for the entire channel of a trip function that will ensure, within the required level of confidence, that sufficient allocation exists between this actual trip function actuation point and the analytical limit. The Allowable Value is more conservative than the Analytical Limit to account for instrument uncertainties that either are not present or are not measured during periodic testing.

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Channel uncertainties that either are not present or are not measured during periodic testing may include design basis accident temperature and radiation effects (Ref. 5) or process dependent effects. The channel allowable value for each RPS function is controlled by Technical Specifications and is listed in Table 3.3.1-1, Reactor Protection System Instrumentation.

d. Calibration acceptance criteria (i.e., setpoints) are established by plant administrative programs for the components of a channel (i.e., required sensor, alarm, interlock, display, and trip function). The calibration acceptance criteria are established to ensure, within the required level of confidence, that the Allowable Value for the entire channel will not be exceeded during the calibration interval.

A description of the methodology used to calculate the channel allowable values and calibration acceptance criteria is provided in References 6 and 8.

Setpoints in accordance with the Allowable Value ensure that the consequences of Design Basis Accidents (DBAs) will be acceptable, providing the unit is operated from within the LCOs at the onset of the DBA and the equipment functions as designed.

Each channel required to be OPERABLE can be tested on line to verify that the signal processing equipment and setpoint accuracy is within the specified allowance requirements of Reference 2. Once a designated channel is taken out of service for testing, a simulated signal is injected in place of the field instrument signal. The process equipment for the channel in test is then tested, verified, and calibrated. SRs for the channels are specified in the SR section.

The Allowable Values listed in Table 3.3.2-1 and the Trip Setpoints calculated to ensure that Allowable Values are not exceeded during the calibration interval are based on the methodology described in calculations performed in accordance with Reference 6. All field sensors and signal processing

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BACKGROUND (Continued)

equipment for these channels are assumed to operate within the allowances of these uncertainty magnitudes.

ESFAS Relay Logic Protection System

The relay logic equipment is used for the decision logic processing of outputs from the signal processing equipment bistables. To meet the redundancy requirements, two trains of relay logic, each performing the same functions, are provided. If one train is taken out of service for maintenance or test purposes, the second train will provide ESF actuation for the unit. Each train is packaged in a cabinet for physical and electrical separation to satisfy separation and independence requirements.

The relay logic performs the decision logic for most ESF equipment actuation; generates the electrical output signals that initiate the required actuation; and provides the status, permissive, and annunciator output signals to the main control room.

The bistable outputs from the signal processing equipment are sensed by the relay logic equipment and combined into logic that represent combinations indicative of various transients. If a required logic combination is completed, the system will send actuation signals via master and slave relays to those components whose aggregate Function best serves to alleviate the condition and restore the unit to a safe condition. Examples are given in the Applicable Safety Analyses, LCO, and Applicability sections of this Bases.

Each relay logic train has a built in testing capability that can test the decision logic matrix functions and the actuation devices while the unit is at power. When any one train is taken out of service for testing, the other train is capable of providing unit monitoring and protection until the testing has been completed.

The actuation of ESF components is accomplished through master and slave relays. The relay logic energizes the master relays

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BACKGROUND (Continued)

appropriate for the condition of the unit. Each master relay then energizes one or more slave relays, which then cause actuation of the end devices. The master and slave relays are routinely tested to ensure operation.

APPLICABLE SAFETY ANALYSES, LCO, AND APPLICABILITY

Each of the analyzed accidents can be detected by one or more ESFAS Functions. One of the ESFAS Functions is the primary actuation signal for that accident. An ESFAS Function may be the primary actuation signal for more than one type of accident. An ESFAS Function may also be a secondary, or backup, actuation signal for one or more other accidents. For example, Pressurizer Pressure-Low is a primary actuation signal for small loss of coolant accidents (LOCAs) and a backup actuation signal for steam line breaks (SLBs) outside containment. Functions such as manual initiation, not specifically credited in the accident safety analysis, are qualitatively credited in the safety analysis and the NRC staff approved licensing basis for the unit. These Functions may provide protection for conditions that do not require dynamic transient analysis to demonstrate Function performance. These Functions may also serve as backups to Functions that were credited in the accident analysis (Ref. 3).

The LCO requires all instrumentation performing an ESFAS Function identified in Table 3.3.2-1 to be OPERABLE. Failure of any instrument renders the affected channel(s) inoperable and reduces the reliability of the affected Functions.

The LCO generally requires OPERABILITY of four or three channels in each instrumentation function and two channels in each logic and manual initiation function. The two-out-of-three and the two-out-of-four configurations allow one channel to be tripped during maintenance or testing without causing an ESFAS initiation. Two logic or manual initiation channels are required to ensure no single random failure disables the ESFAS.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The required channels of ESFAS instrumentation provide unit protection in the event of any of the analyzed accidents. ESFAS protection functions are as follows:

1. Safety Injection

Safety Injection (SI) provides two primary functions:

1. Primary side water addition to ensure maintenance or recovery of reactor vessel water level (coverage of the active fuel for heat removal, clad integrity, and for limiting peak clad temperature to < 2200°F); and

2. Boration to ensure recovery and maintenance of SDM (k_{eff} < 1.0).

These functions are necessary to mitigate the effects of high energy line breaks (HELBs) both inside and outside of containment. The SI signal is also used to initiate other Functions such as:

- Phase A Isolation;
- Containment Isolation;
- Reactor Trip;
- Turbine Trip;
- Feedwater Isolation;
- Start of auxiliary feedwater (AFW) pumps; and
- Control room ventilation actuation to the 10% incident mode.

These other functions ensure:

- Isolation of nonessential systems through containment penetrations;

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

- Trip of the turbine and reactor to limit power generation;
- Isolation of main feedwater (MFW) to limit secondary side mass losses;
- Start of AFW to ensure secondary side cooling capability; and
- Isolation of the control room to ensure habitability.

a. <u>Safety Injection-Manual Initiation</u>

The LCO requires one channel per train to be OPERABLE. The operator can initiate both trains of SI at any time by using either of two push buttons in the control room. This action will cause actuation of all components in the same manner as any of the automatic actuation signals.

The LCO for the Manual Initiation Function ensures the proper amount of redundancy is maintained in the manual ESFAS actuation circuitry to ensure the operator has manual ESFAS initiation capability.

Each channel consists of one push button and the interconnecting wiring to the actuation logic cabinet. Each push button actuates both trains. This configuration does not allow testing at power.

b. <u>Safety Injection-Automatic Actuation Logic and Actuation Relays</u>

This LCO requires two trains to be OPERABLE. Actuation logic consists of all circuitry within the actuation subsystems, including the initiating relay contacts responsible for actuating the ESF equipment.

Manual and automatic initiation of SI must be OPERABLE in MODES 1, 2, and 3. In these MODES, there is

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

sufficient energy in the primary and secondary systems to warrant automatic initiation of ESF systems. Manual Initiation is also required in MODE 4 even though automatic actuation is not required. In this MODE, adequate time is available to manually actuate required components in the event of a DBA, but because of the large number of components actuated on a SI, actuation is simplified by the use of the manual actuation push buttons. Automatic actuation logic and actuation relays must be OPERABLE in MODE 4 as needed to support system level manual initiation.

These Functions are not required to be OPERABLE in MODES 5 and 6 because there is adequate time for the operator to evaluate unit conditions and respond by manually starting individual systems, pumps, and other equipment to mitigate the consequences of an abnormal condition or accident. Unit pressure and temperature are very low and many ESF components are administratively locked out or otherwise prevented from actuating to prevent inadvertent overpressurization of unit systems.

c. <u>Safety Injection-Containment Pressure-High</u>

This signal provides protection against the following accidents:

- SLB inside containment; and
- LOCA.

Containment Pressure-High provides no input to any control functions. Thus, three OPERABLE channels are sufficient to satisfy protective requirements with a two-out-of-three logic. The transmitters (d/p cells) and electronics are located outside of containment with the sensing line (high pressure side of the transmitter) located inside containment.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Thus, the high pressure Function will not experience any adverse environmental conditions and the Trip Setpoint reflects only steady state instrument uncertainties.

Containment Pressure-High must be OPERABLE in MODES 1, 2, and 3 when there is sufficient energy in the primary and secondary systems to pressurize the containment following a pipe break. In MODES 4, 5, and 6, there is insufficient energy in the primary or secondary systems to pressurize the containment.

d. Safety Injection-Pressurizer Pressure-Low

This signal provides protection against the following accidents:

- Inadvertent opening of a steam generator (SG) relief or safety valve;
- SLB;
- Inadvertent opening of a pressurizer relief or safety valve;
- LOCAs; and
- SG Tube Rupture.

Three channels of pressurizer pressure provide input into the ESFAS actuation logic. These channels initiate the ESFAS automatically when two of the three channels exceed the low pressure setpoint. These protection channels also provide control functions; however, the two-out-of-three logic is considered adequate to provide the required protection.
The transmitters are located inside containment, with the taps in the vapor space region of the pressurizer, and thus possibly experiencing adverse environmental conditions (LOCA, SLB inside containment, rod

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

ejection). Therefore, the Trip Setpoint reflects the inclusion of both steady state and adverse environmental instrument uncertainties.

This Function must be OPERABLE in MODES 1, 2, and 3 (above the Pressurizer Pressure Interlock (Function 7) to mitigate the consequences of an HELB inside containment. This signal may be manually blocked by the operator below the Pressurizer Pressure Interlock (Function 7) setpoint. Automatic SI actuation below this pressure setpoint is performed by the Containment Pressure-High signal.

This Function is not required to be OPERABLE in MODE 3 below the Pressurizer Pressure Interlock (Funtion 8) setpoint. Other ESF functions are used to detect accident conditions and actuate the ESF systems in this MODE. In MODES 4, 5, and 6, this Function is not needed for accident detection and mitigation.

e. <u>Safety Injection- High Differential Pressure Between Steam Lines</u>

Steam Line Pressure – High Differential Pressure Between Steam Lines provides protection against the following accidents:

- SLB; and
- Inadvertent opening of an ADV or an SG safety valve.

High Differential Pressure Between Steam Lines provides no input to any control functions. Thus, three OPERABLE channels on each steam line are sufficient to satisfy the requirements, with a two-out-of-three logic on each steam line.

With the transmitters located inside the auxiliary feed pump room, it is possible for them to experience

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

adverse environmental conditions during a HELB event. Therefore, the Trip Setpoint reflects both steady state and adverse environmental instrument uncertainties.

Steam line high differential pressure must be OPERABLE in MODES 1, 2, and 3 when a secondary side break or stuck open valve could result in the rapid depressurization of the steam line(s). This Function is not required to be OPERABLE in MODE 4, 5, or 6 because there is not sufficient energy in the secondary side of the unit to cause an accident.

f, g. <u>Safety Injection-High Steam Flow in Two Steam Lines Coincident With T_{avg}-Low or Coincident With Steam Line Pressure-Low</u>

These Functions (1.f and 1.g) provide protection against the following accidents:

- SLB; and
- the inadvertent opening of a SG safety valve.

Two steam line flow channels per steam line are required OPERABLE for these Functions. The steam line flow channels are combined in a one-out-of-two logic to indicate high steam flow in one steam line. The steam flow transmitters provide control inputs, but the control function cannot cause the events that the Function must protect against. Therefore, two channels are sufficient to satisfy redundancy requirements. The one-out-of-two configuration allows online testing because trip of one high steam flow channel is not sufficient to cause initiation. High steam flow in two steam lines is acceptable in the case of a single steam line fault due to the fact that the remaining intact steam lines will pick up the full turbine load. The increased steam flow in the remaining intact lines will actuate the required

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

second high steam flow trip. Additional protection is provided by Function 1.e., High Differential Pressure Between Steam Lines.

One channel of T_{avg} per loop and one channel of low steam line pressure per steam line are required OPERABLE. For each parameter, the channels for all loops or steam lines are combined in a logic such that two channels tripped will cause a trip for the parameter. The Function trips on one-out-of-two high steam flow in any two-out-of-four steam lines if there is one-out-of-one low T_{avg} trip in any two-out-of-four RCS loops, or if there is a one-out-of-one low pressure trip in any two-out-of-four steam lines. Since the accidents that this event protects against cause both low steam line pressure and low T_{avg}, provision of one channel per loop or steam line ensures no single random failure can disable both of these Functions. The steam line pressure channels provide no control inputs. The T_{avg} channels provide control inputs, but the control function cannot initiate events that the Function acts to mitigate.

The Allowable Value for high steam flow is a linear function that varies with power level. The function is a turbine first stage pressure corresponding to approximately 54% of full steam flow between 0% and 20% load to approximately 110% of full steam flow at 100% load. The nominal trip setpoint is similarly calculated.

With the transmitters located inside the containment (RCS temperature and steam line flow) or inside the auxiliary feedwater building (steam pressure), it is possible for them to experience adverse steady state environmental conditions during an SLB event. Therefore, the Trip Setpoint reflects both steady state and adverse environmental instrument uncertainties.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

This Function must be OPERABLE in MODES 1, 2, and 3 when any MSIV is open because a secondary side break or stuck open valve could result in the rapid depressurization of the steam line(s). SLB may be addressed by Containment Pressure High (inside containment) or by High Steam Flow in Two Steam Lines coincident with Steam Line Pressure - Low, for Steam Line Isolation, followed by High Differential Pressure Between Two Steam Lines, for SI. This Function is not required to be OPERABLE in MODE 4, 5, or 6 because there is insufficient energy in the secondary side of the unit to cause an accident.

2. <u>Containment Spray</u>

Containment Spray provides three primary functions:

1. Lowers containment pressure and temperature after an HELB in containment;
2. Reduces the amount of radioactive iodine in the containment atmosphere; and
3. Adjusts the pH of the water in the containment and recirculation sump after a large break LOCA.

These functions are necessary to:

- Ensure the pressure boundary integrity of the containment structure;
- Limit the release of radioactive iodine to the environment; and
- Minimize corrosion of the components and systems inside containment following a LOCA.

The containment spray actuation signal starts the containment spray pumps. Water is drawn from the RWST by the containment spray pumps and mixed with a sodium

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

hydroxide solution from the spray additive tank. When the RWST reaches a specified minimum level, the spray pumps are secured. RHR or recirculation pumps will be used if continued containment spray is required. Containment spray is actuated automatically by Containment Pressure-High High.

a. Containment Spray-Manual Initiation

Manual initiation of containment spray (CS) requires that two pushbuttons in the control room be depressed simultaneously which will actuate both trains of CS. Two pushbuttons must be depressed simultaneously to minimize the potential for an inadvertent actuation of CS which could have serious consequences. Each CS pushbutton closes one of the two contacts required to start CS train A and one of the two contacts required to start CS train B; depressing both pushbuttons closes both of the contacts required to start CS train A and both of the contacts required to start CS train B. Two channels (contacts) are required to be Operable for CS train A and two channels (contacts) are required to be Operable for CS train B. Failure of one manual pushbutton will result in one inoperable channel in both trains.

Note that Manual Initiation of containment spray also actuates Phase B containment isolation and containment ventilation isolation.

b. Containment Spray-Automatic Actuation Logic and Actuation Relays

Automatic actuation logic and actuation relays consist of the same features and operate in the same manner as described for ESFAS Function 1.b.

Manual and automatic initiation of containment spray must be OPERABLE in MODES 1, 2, and 3 when there is a potential for an accident to occur, and sufficient

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

energy in the primary or secondary systems to pose a threat to containment integrity due to overpressure conditions. Manual initiation is also required in MODE 4, even though automatic actuation is not required. In this MODE, adequate time is available to manually actuate required components in the event of a DBA. However, because of the number of components actuated on a containment spray, actuation is simplified by the use of the manual actuation push buttons. Automatic actuation logic and actuation relays must be OPERABLE in MODE 4 to support system level manual initiation. In MODES 5 and 6, there is insufficient energy in the primary and secondary systems to result in containment overpressure. In MODES 5 and 6, there is also adequate time for the operators to evaluate unit conditions and respond, to mitigate the consequences of abnormal conditions by manually starting individual components.

c. Containment Spray-Containment Pressure Hi-Hi

This signal provides protection against a LOCA or an SLB inside containment. The transmitters (d/p cells) are located outside of containment with the sensing line (high pressure side of the transmitter) located inside containment. The transmitters and electronics are located outside of containment. Thus, they will not experience any adverse environmental conditions and the Trip Setpoint reflects only steady state instrument uncertainties.

This Function requires the bistable output to energize to perform its required action. It is not desirable to have a loss of power actuate containment spray, because the consequences of an inadvertent actuation of containment spray could be serious. Therefore, the IP3 design consists of 2 sets of 3 channels (i.e., 6 pressure instruments) and 2 channels from each set of 3 are required to energize to actuate Containment Spray. This configuration provides sufficient redundancy to prevent a single failure from

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

causing or preventing Containment Spray initiation even when testing with one inoperable channel already in trip. The Required Actions for an inoperable channel associated with this Function decreases the probability of an inadvertent actuation by allowing no more than one channel per set to be placed in trip.

Containment pressure is not used for control; therefore, this arrangement exceeds the minimum redundancy requirements.

Containment Pressure- High High must be OPERABLE in MODES 1, 2, and 3 when there is sufficient energy in the primary and secondary sides to pressurize the containment following a pipe break. In MODES 4, 5, and 6, there is insufficient energy in the primary and secondary sides to pressurize the containment and reach the Containment Pressure High High setpoint.

3. Containment Isolation

Containment Isolation provides isolation of the containment atmosphere, and selected process systems that penetrate containment. This Function is necessary to prevent or limit the release of radioactivity to the environment in the event of a large break LOCA.

There are two separate Containment Isolation signals, Phase A and Phase B. Phase A isolation isolates all automatically isolable process lines exiting containment, except component cooling water (CCW) and RCP seal return, at a relatively low containment pressure indicative of primary or secondary system leaks. For these types of events, forced circulation cooling using the reactor coolant pumps (RCPs) and SGs is the preferred (but not required) method of decay heat removal. Since CCW or RCP seal injection and return are required to support RCP operation, not isolating CCW and RCP seal return on the low pressure Phase A signal enhances unit safety by allowing operators to use forced RCS circulation to cool the unit.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Isolating these functions on the low pressure signal may force the use of feed and bleed cooling, which could prove more difficult to control.

Phase A containment isolation is actuated automatically by SI, or manually via the actuation logic. All process lines exiting containment, with the exception of CCW and RCP seal return, are isolated. CCW and RCP seal return are not isolated at this time to permit continued operation of the RCPs with cooling water flow to the thermal barrier heat exchangers and oil coolers. All process lines not equipped with remote operated isolation valves are manually closed, or otherwise isolated, prior to MODE 4 except those manual isolation valves needed to support plant operations.

Manual Phase A Containment Isolation is accomplished by either of two pushbuttons in the control room. Either push button actuates both trains. Note that manual actuation of Phase A Containment Isolation also actuates Containment Ventilation Isolation.

The Phase B signal isolates CCW and RCP seal return. This occurs at a relatively high containment pressure that is indicative of a large break LOCA or an SLB. For these events, forced circulation using the RCPs is no longer desirable. Isolating the CCW at the higher pressure does not pose a challenge to the containment boundary because the CCW System is a closed loop inside containment. Although some CCW system components may not meet all of the ASME Code requirements applied to the containment itself, the system is continuously pressurized to a pressure greater than the Phase B setpoint. Thus, routine operation demonstrates the integrity of the system pressure boundary for pressures exceeding the Phase B setpoint. Furthermore, because system pressure exceeds the Phase B setpoint, any system leakage prior to initiation of Phase B isolation would be into containment. Therefore, the combination of CCW System design and Phase B isolation ensures the CCW System is not a potential path for radioactive release from containment.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Phase B containment isolation is actuated by Containment Pressure-High High, or manually, via the actuation logic, as previously discussed. For containment pressure to reach a value high enough to actuate Containment Pressure-High High, a large break LOCA or SLB must have occurred and containment spray must have been actuated. RCP operation will no longer be required and CCW and seal return to the RCPs are, therefore, no longer necessary. The RCPs can be operated with seal injection flow alone and without CCW flow to the thermal barrier heat exchanger.

Manual Phase B Containment Isolation is accomplished by either of two pushbuttons in the control room. Either pushbutton actuates both trains. Manual Phase B Containment Isolation is also initiated by Containment Spray manual pushbuttons. CS pushbuttons are depressed simultaneously, Phase B Containment Isolation and Containment Spray will be actuated in both trains.

a. <u>Containment Isolation-Phase A Isolation</u>

(1) <u>Phase A Isolation-Manual Initiation</u>

Manual Phase A Containment Isolation is actuated by either of two pushbuttons in the control room. Either pushbutton actuates both trains. Note that manual initiation of Phase A Containment Isolation also actuates Containment Ventilation Isolation.

(2) <u>Phase A Isolation-Automatic Actuation Logic and Actuation Relays</u>

Automatic Actuation Logic and Actuation Relays consist of the same features and operate in the same manner as described for ESFAS Function 1.b.

Manual and automatic initiation of Phase A Containment Isolation must be OPERABLE in

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

MODES 1, 2, and 3, when there is a potential for an accident to occur. Manual initiation is also required in MODE 4 even though automatic actuation is not required. In this MODE, adequate time is available to manually actuate required components in the event of a DBA, but because of the large number of components actuated on a Phase A Containment Isolation, actuation is simplified by the use of the manual actuation push buttons. Automatic actuation logic and actuation relays must be OPERABLE in MODE 4 only if needed to support system level manual initiation. In MODES 5 and 6, there is insufficient energy in the primary or secondary systems to pressurize the containment to require Phase A Containment Isolation. There also is adequate time for the operator to evaluate unit conditions and manually actuate individual isolation valves in response to abnormal or accident conditions.

(3) Phase A Isolation-Safety Injection

Phase A Containment Isolation is also initiated by all Functions that initiate SI. The Phase A Containment Isolation requirements for these Functions are the same as the requirements for their SI function. Therefore, the requirements are not repeated in Table 3.3.2-1. Instead, Function 1, SI, is referenced for all initiating Functions and requirements.

b. Containment Isolation-Phase B Isolation

Phase B Containment Isolation is accomplished by Manual Initiation, Automatic Actuation Logic and Actuation Relays, and by Containment Pressure channels (the same channels that actuate Containment Spray, Function 2). The Containment Pressure trip of Phase B Containment Isolation is energized to trip in order to

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

minimize the potential of spurious trips that may damage the RCPs.

(1) <u>Phase B Isolation-Manual Initiation</u>

Manual Phase B Containment Isolation is accomplished by either of two pushbuttons in the control room. Either pushbutton actuates both trains.

(2) <u>Phase B Isolation-Automatic Actuation Logic and Actuation Relays</u>

Manual and automatic initiation of Phase B containment isolation must be OPERABLE in MODES 1, 2, and 3, when there is a potential for an accident to occur. Manual initiation is also required in MODE 4 even though automatic actuation is not required. In this MODE, adequate time is available to manually actuate required components in the event of a DBA. However, because of the number of components actuated on a Phase B containment isolation, actuation is simplified by the use of the manual actuation push buttons. Automatic actuation logic and actuation relays must be OPERABLE in MODE 4 to support system level manual initiation. In MODES 5 and 6, there is insufficient energy in the primary or secondary systems to pressurize the containment to require Phase B containment isolation. There also is adequate time for the operator to evaluate unit conditions and manually actuate individual isolation valves in response to abnormal or accident conditions.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

(3) Phase B Isolation-Containment Pressure Hi-Hi

The basis for containment pressure MODE applicability is as discussed for ESFAS Function 2.c above.

4. Steam Line Isolation

Isolation of the main steam lines provides protection in the event of an SLB inside or outside containment. Rapid isolation of the steam lines will limit the steam break accident to the blowdown from one SG, even if Main Steam Check Valve fails. For an SLB upstream of the main steam isolation valves (MSIVs), inside or outside of containment, closure of the MSIVs limits the accident to the blowdown from only the affected SG. For an SLB downstream of the MSIVs, closure of the MSIVs terminates the accident.

a. Steam Line Isolation-Manual Initiation

Manual initiation of Steam Line Isolation can be accomplished from the control room. Each main steam isolation valve (MSIV) will close if either of two solenoid valves in parallel (channel A and channel B) are opened. The pair of solenoid valves associated with each MSIV are operated by a single switch and there is a separate switch for each MSIV. Each of these switches actuates two channels. Except for the switch in the control room which is common to both channels, there are two separate and redundant circuits (channel A and channel B) capable of closing each MSIV. Therefore, the LCO requires 2 channels per MSIV and each MSIV is considered a separate Function.

b. Steam Line Isolation-Automatic Actuation Logic and Actuation Relays

Automatic actuation logic and actuation relays consist of the same features and operate in the same manner as described for ESFAS Function 1.b.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Manual and automatic initiation of steam line isolation must be OPERABLE in MODES 1, 2, and 3 when there is sufficient energy in the RCS and SGs to have an SLB or other accident. This could result in the release of significant quantities of energy and cause a cooldown of the primary system. The Steam Line Isolation Function is required in MODES 2 and 3 unless all MSIVs are closed. In MODES 4, 5, and 6, there is insufficient energy in the RCS and SGs to experience an SLB or other accident releasing significant quantities of energy.

c. Steam Line Isolation-Containment Pressure (Hi-Hi)

This Function actuates closure of the MSIVs in the event of a LOCA or an SLB inside containment to limit the mass and energy release to containment. The transmitters (d/p cells) are located outside containment. Containment Pressure-High-High provides no input to any control functions. The transmitters and electronics are located outside of containment. Thus, they will not experience any adverse environmental conditions, and the Trip Setpoint reflects only steady state instrument uncertainties.

The IP3 design consists of 2 sets of 3 channels and 2 channels from each set of 3 are required to energize to actuate steam line isolation on high pressure in the containment. This is the same logic that initiates Containment Spray. Therefore, this logic is designed to provide sufficient redundancy to prevent a single failure from causing or preventing Containment Spray initiation even when testing with one inoperable channel already in trip. The Required Action for an inoperable channel associated with this Function is modified by a Note that permits no more than one channel per set to be placed in trip to decrease the probability of an inadvertent actuation.

Containment Pressure-High-High must be OPERABLE in MODES 1, 2, and 3, when there is sufficient energy in

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

the primary and secondary side to pressurize the containment following a pipe break. This would cause a significant increase in the containment pressure, thus allowing detection and closure of the MSIVs. The Steam Line Isolation Function remains OPERABLE in MODES 2 and 3 unless all MSIVs are closed. In MODES 4, 5, and 6, there is not enough energy in the primary and secondary sides to pressurize the containment to the Containment Pressure – High-High setpoint.

d, e. Steam Line Isolation – High Steam Flow in Two Steam Lines Coincident with T_{avg}-Low or Coincident With Steam Line Pressure-Low

These Functions (4.d and 4.e) provide closure of the MSIVs during an SLB or inadvertent opening of a safety valve to limit RCS cooldown and the mass and energy release to containment.

These Functions were discussed previously as Functions 1.e. and 1.f.

These Functions must be OPERABLE in MODES 1 and 2, and in MODE 3, when a secondary side break or stuck open valve could result in the rapid depressurization of the steam lines unless all MSIVs are closed. These Functions are not required to be OPERABLE in MODES 4, 5, and 6 because there is insufficient energy in the secondary side of the unit to have an accident.

5. Feedwater Isolation

The function of the Feedwater Isolation signal is to stop the excessive flow of feedwater into the SGs. The Function is necessary to mitigate the effects of a high water level in the SGs, which could result in carryover of water into the steam lines and excessive cooldown of the primary

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

system. The SG high water level is due to excessive feedwater flows.

This Function is actuated by an SI signal. The RPS also initiates a turbine trip signal whenever a reactor trip is generated. In the event of SI, the unit is taken off line and the turbine generator must be tripped. The MFW System is also taken out of operation and the AFW System is automatically started. The SI signal was discussed previously.

Feedwater Isolation-Safety Injection

Feedwater Isolation is also initiated by all Functions that initiate SI. Therefore, there are two trains of this Function, one initiated by SI train A and one initiated by SI train B.

Feedwater Isolation Functions must be OPERABLE in MODES 1 and 2 and 3 except when all MBFPDVs or MBFRVs and associated low flow bypass valves are closed or isolated by a closed manual valve when the MFW System is in operation. In MODES 4, 5, and 6, the MFW System is not in service and this Function is not required to be OPERABLE.

6. Auxiliary Feedwater

The AFW System is designed to provide a secondary side heat sink for the reactor in the event that the MFW System is not available. The system has two motor driven pumps and a turbine driven pump, making it available during normal unit operation, during a loss of AC power and during a loss of MFW. The normal source of water for the AFW System is the condensate storage tank (CST). Additionally, City Water (CW) may be aligned to AFW to provide a backup water supply. The AFW System is aligned so that upon a motor driven pump start, flow is initiated to the respective SGs immediately.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

a. Auxiliary Feedwater-Automatic Actuation Logic and Actuation Relays

Automatic actuation logic and actuation relays consist of the same features and operate in the same manner as described for ESFAS Function 1.b.

b. Auxiliary Feedwater-Steam Generator Water Level-Low Low

SG Water Level-Low Low provides protection against a loss of heat sink due to a loss of MFW and the resulting loss of SG water level.

Signals from two-out-of-three channels from any one SG will start the motor driven AFW pumps. Signals from two-out-of-three channels from any two SGs will start the steam driven AFW pump. The LCO requires three OPERABLE channels per steam generator.

With the transmitters (d/p cells) located inside containment and thus possibly experiencing adverse environmental conditions, the Trip Setpoint reflects the inclusion of both steady state and adverse environmental instrument uncertainties.

c. Auxiliary Feedwater-Safety Injection

An SI actuation starts the motor driven AFW pumps. The AFW initiation functions are the same as the requirements for their SI function. Therefore, the requirements are not repeated in Table 3.3.2-1. Instead, Function 1, SI, is referenced for all initiating functions and requirements.

d. Auxiliary Feedwater-Loss of Offsite Power

A turbine trip in conjunction with a loss of offsite power to the safeguards buses will be accompanied by a loss of reactor coolant pumping power and the

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

subsequent need for some method of decay heat removal. The loss of offsite power (Non SI blackout signal) is detected by a voltage drop on 480 V bus 3A and/or 6A. Loss of power to either safeguards bus will start the turbine driven AFW pump 32 to ensure that at least one SG contains enough water to serve as the heat sink for reactor decay heat and sensible heat removal following the reactor trip following a loss of offsite power.

The LCO requires one Operable channel for bus 3A and one Operable channel for bus 6A. Either channel will start the turbine driven AFW pump. Therefore, a single failure of one channel of non-Safety Injection blackout sequence will not result in a loss of Function.

Functions 6.a through 6.d must be OPERABLE in MODES 1, 2, and 3 to ensure that the SGs remain the heat sink for the reactor. SG Water Level – Low Low in any operating SG will cause the motor driven AFW pump to start. The system is aligned so that upon a start of the pump, water immediately begins to flow to the SGs. SG Water Level – Low Low in any two operating SGs will cause the turbine driven pump to start. These Functions do not have to be OPERABLE in MODES 5 and 6 because there is not enough heat being generated in the reactor to require the SGs as a heat sink. In MODE 4, AFW actuation does not need to be OPERABLE because either AFW or residual heat removal (RHR) will already be in operation to remove decay heat or sufficient time is available to manually place either system in operation.

e. Auxiliary Feedwater-Trip of Main Feedwater Pumps

A Trip of either MBFW pump is an indication of a potential loss of MFW and the potential need for some method of decay heat and sensible heat removal to bring the reactor back to no load temperature and pressure. Each turbine driven MBFW pump is equipped

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

with a pressure switch on the control oil line for the speed control system. A low pressure signal from this pressure switch indicates a trip of that pump. The single channel associated with each operating MBFP will start both motor driven AFW pumps. However, there is no single failure tolerance for this Function unless both MBFPs are operating. This is acceptable because this is a backup method for starting AFW and other Functions, in particular SG Water Level – Low Low, provide the primary protection against a loss of heat sink. The LCO requires one Operable channel for each operating MBFP. A trip of either MBFW pump starts both motor driven AFW pumps to ensure that at least one SG is available with water to act as the heat sink for the reactor.

Function 6.e must be OPERABLE in MODES 1 and 2. This ensures that at least one SG is provided with water to serve as the heat sink to remove reactor decay heat and sensible heat in the event of loss of normal feedwater. In MODES 3, 4, and 5, the MBFW pumps are shut down, and thus MBFW pump trip does not require automatic AFW initiation.

7. <u>ESFAS Interlock-Pressurizer Pressure</u>

The Pressurizer Pressure interlock permits a normal unit cooldown and depressurization without actuation of SI. With two-out-of-three pressurizer pressure channels (discussed previously) less than the setpoint, the operator can manually block the Pressurizer Pressure-Low SI signal. With two-out-of-three pressurizer pressure channels above the setpoint, the Pressurizer Pressure-Low is automatically enabled. The operator can also enable these trips by use of the respective manual blocking switches.

This Function must be OPERABLE in MODES 1, 2, and 3 to allow an orderly cooldown and depressurization of the

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

unit without the actuation of SI. The interlock Functions back up manual actions to ensure bypassable functions are in operation under the conditions assumed in the safety analyses. This Function does not have to be OPERABLE in MODE 4, 5, or 6 because system pressure must already be below the setpoint for the requirements of the heatup and cooldown curves to be met.

The ESFAS instrumentation satisfies Criterion 3 of 10 CFR 50.36.

ACTIONS

Note 1 has been added in the ACTIONS to clarify the application of Completion Time rules. The Conditions of this Specification may be entered independently for each Function listed on Table 3.3.2-1.

Note 2 specifies that when a channel or train is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 8 hours, provided the associated Function(s) maintains ESFAS trip capability. Upon completion of the Surveillance, or expiration of the 8 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is consistent with the assumptions of the instrumentation system reliability analysis (Ref. 7). That analysis demonstrated that the 8 hour testing allowance does not significantly reduce the probability that the ESFAS will trip when necessary.

In the event a channel's Trip Setpoint is found nonconservative with respect to the Allowable Value, or the transmitter, instrument Loop, signal processing electronics, or bistable is found inoperable, then all affected Functions provided by that channel must be declared inoperable and the LCO Condition(s) entered for the protection Function(s) affected. When the Required Channels in Table 3.3.2-1 are specified (e.g., on a per steam line, per loop, per SG, etc., basis), then the Condition may be entered separately for each steam line, loop, SG, etc., as appropriate.

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ACTIONS (continued)

When the number of inoperable channels in a trip function exceed those specified in one or other related Conditions associated with a trip function, then the unit is outside the safety analysis. Therefore, LCO 3.0.3 should be immediately entered if applicable in the current MODE of operation.

A.1

Condition A applies to all ESFAS protection functions.

Condition A addresses the situation where one or more channels or trains for one or more Functions are inoperable at the same time. The Required Action is to refer to Table 3.3.2-1 and to take the Required Actions for the protection functions affected. The Completion Times are those from the referenced Conditions and Required Actions.

B.1, B.2.1 and B.2.2

Condition B applies to manual initiation of:

- SI;
- Containment Spray;
- Phase A Isolation; and
- Phase B Isolation.

This action addresses the train orientation of the relay logic for the functions listed above. If a channel or train is inoperable, 48 hours is allowed to return it to an OPERABLE status. Note that for containment spray and Phase B isolation, failure of one or both channels in one train renders the train inoperable. Condition B, therefore, encompasses both situations.

The specified Completion Time is reasonable considering that there are two automatic actuation trains and another manual initiation train OPERABLE for each Function, and the low probability of an event occurring during this interval. If the

BASES

ACTIONS

B.1, B.2.1 and B.2.2 (continued)

train cannot be restored to OPERABLE status, the unit must be placed in a MODE in which the LCO does not apply. This is done by placing the unit in at least MODE 3 within an additional 6 hours (54 hours total time) and in MODE 5 within an additional 30 hours (84 hours total time). The allowable Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

C.1, C.2.1 and C.2.2

Condition C applies to the automatic actuation logic and actuation relays for the following functions:

- SI;
- Containment Spray;
- Phase A Isolation; and
- Phase B Isolation.

This action addresses the train orientation of the relay logic and the master and slave relays. If one train is inoperable, 6 hours are allowed to restore the train to OPERABLE status. The specified Completion Time is reasonable considering that there is another train OPERABLE, and the low probability of an event occurring during this interval. If the train cannot be restored to OPERABLE status, the unit must be placed in a MODE in which the LCO does not apply. This is done by placing the unit in at least MODE 3 within an additional 6 hours (12 hours total time) and in MODE 5 within an additional 30 hours (42 hours total time). The Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

BASES

ACTIONS

C.1, C.2.1 and C.2.2 (continued)

The Required Actions are modified by a Note that allows one train to be bypassed for up to 8 hours for surveillance testing, provided the other train is OPERABLE. This allowance is based on the reliability analysis assumption of WCAP-10271-P-A (Ref. 7) that 8 hours is required to perform channel surveillance.

D.1, D.2.1 and D.2.2

Condition D applies to:

- Containment Pressure-High;
- Pressurizer Pressure-Low;
- High Differential Pressure Between Steam Lines;
- High Steam Flow in Two Steam Lines Coincident With T_{avg}-Low or Coincident With Steam Line Pressure-Low; and
- SG Water level-Low Low.

If one channel is inoperable, 6 hours are allowed to restore the channel to OPERABLE status or to place it in the tripped condition. Generally this Condition applies to functions that operate on two-out-of-three logic. Therefore, failure of one channel places the Function in a two-out-of-two configuration. One channel must be tripped to place the Function in a one-out-of-two configuration that satisfies redundancy requirements.

Required Actions associated with High Steam Flow in Two Steam Lines Coincident With Tavg-Low or Coincident With Steam Line Pressure-Low are entered by treating Steam Flow, Tavg, and Steam Line Pressure as three separate Functions. The protective action is initiated on one-out-of-two high flow in any two-out-of-four steam lines if there is one-out-of-one low Tavg trip in any two-out-of-four RCS loops, or if there is a one-out-of-one low pressure trip in any two-out-of-four steam lines. This logic is

BASES

ACTIONS

D.1, D.2.1 and D.2.2 (continued)

acceptable because a single steam line fault will cause the remaining intact steam lines to pick up the full turbine load with the protective action initiated by the conditions in the non faulted steam lines. Therefore, a maximum of one channel of each of the three Functions may be placed in trip without creating a condition where a single failure will either cause or prevent the protective action.

Failure to restore the inoperable channel to OPERABLE status or place it in the tripped condition within 6 hours requires the unit be placed in MODE 3 within the following 6 hours and MODE 4 within the next 6 hours.

The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems. In MODE 4, these Functions are no longer required OPERABLE.

The Required Actions are modified by a Note that allows the inoperable channel to be bypassed for up to 8 hours for surveillance testing of other channels. The 6 hours allowed to restore the channel to OPERABLE status or to place the inoperable channel in the tripped condition, and the 8 hours allowed for testing, are justified in Reference 8.

E.1, E.2.1 and E.2.2

Condition E applies to:

- Steam Line Isolation Containment Pressure-(High High);
- Containment Spray Containment Pressure-(High, High); and
- Containment Phase B Isolation Containment Pressure-(High, High).

The IP3 design for the Containment Pressure (High High) ESFAS Function consists of 2 sets of 3 channels. This design requires

BASES

ACTIONS

E.1, E.2.1 and E.2.2 (continued)

that 2 channels from each set of 3 are energized to actuate the Containment Spray or Steam Line Isolation Functions. This configuration provides sufficient redundancy to prevent a single failure from causing or preventing containment spray initiation or steamline isolation even when testing with one inoperable channel per set already in trip.

Note that Condition E applies only when no more than one channel in one or both sets is inoperable. Otherwise, entry into LCO 3.0.3 is required. This is required because two inoperable channels from the same set that fail low could result in a loss of containment spray initiation or steamline isolation when a Containment Pressure (High High) ESFAS initiation is required. Additionally, this ensures that no more than one channel per set can be placed in trip which is required to decrease the probability of an inadvertent actuation of containment spray or steamline isolation if additional channels fail high.

An inoperable channel is placed in trip within 6 hours to limit the amount of time that a single failure of a different channel on the same set could result in the failure of containment spray or steamline isolation to actuate. With no more than one channel from each set in trip, a single failure will not cause or prevent containment spray initiation or steamline isolation. Failure to place an inoperable channel in trip within 6 hours, requires the unit be placed in MODE 3 within the following 6 hours and MODE 4 within the next 6 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems. In MODE 4, these Functions are no longer required OPERABLE.

The Required Actions are modified by a Note that allows one additional channel to be bypassed for up to 8 hours for surveillance testing. Placing a second channel in the bypass condition for up to 8 hours for testing purposes is acceptable based on the results of Reference 7.

BASES

ACTIONS (continued)

F.1, F.2.1 and F.2.2

Condition F applies to:

- Manual Initiation of Steam Line Isolation; and
- Loss of Offsite Power (Non Safety Injection).

For the manual MSIV isolation Function, each MSIV will close if either of the two channels required per MSIV is tripped. If one channel is inoperable, the ability to tolerate a single failure is lost but manual isolation capability is maintained. Therefore, an inoperable channel cannot be placed in trip without causing an actuation and the inoperable channel must be restored to Operable to restore single failure protection. Additionally, since a single switch actuates both channels for each MSIV, the failure of a manual switch may result in the failure of both channels and a loss of Function. The specified Completion Time, 48 hours to restore an inoperable channel, is reasonable considering that there are two automatic actuation trains and another manual initiation train OPERABLE for each MSIV, and the low probability of an event occurring during this interval. Each MSIV is considered a separate Function.

For the Loss of Offsite Power (Non-Safety Injection) Function, either channel (bus 3A or bus 6A) will start the turbine driven AFW pump. If one channel is inoperable, the AFW starting Function for the turbine driven AFW pump on loss of offsite power is maintained by the channel associated with the other bus. Two inoperable channels result in a loss of this Function; therefore, entry into LCO 3.0.3 is requried.

For the Loss of Offsite Power (Non-Safety Injection) Function, an inoperable channel cannot be placed in trip without causing an actuation; therefore, an inoperable channel must be restored to Operable. The specified Completion Time, 48 hours to restore an inoperable channel, is reasonable considering that this is a Non-Safety Injection start of the AFW, the availability of manual starting capability, and the low probability of an event

BASES

ACTIONS

F.1, F.2.1 and F.2.2 (continued)

occurring during this interval. Additionally, other Functions, in particular SG Water Level-Low Low, provide the primary protection against a loss of heat sink.

If either of these Functions cannot be returned to OPERABLE status, the unit must be placed in MODE 3 within the next 6 hours and MODE 4 within the following 6 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power in an orderly manner and without challenging unit systems. In MODE 4, the unit does not have any analyzed transients or conditions that require the explicit use of the protection functions noted above.

G.1, G.2.1 and G.2.2

Condition G applies to the automatic actuation logic and actuation relays for the Steam Line Isolation and AFW actuation Functions.

The action addresses the train orientation of the relay logic and the actuation relays for these functions. If one train is inoperable, 6 hours are allowed to restore the train to OPERABLE status. The Completion Time for restoring a train to OPERABLE status is reasonable considering that there is another train OPERABLE, and the low probability of an event occurring during this interval. If the train cannot be returned to OPERABLE status, the unit must be brought to MODE 3 within the next 6 hours and MODE 4 within the following 6 hours unless the plant can be placed outside of the Applicable MODE or Conditions by other means (e.g., shutting all MSIVs). The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems. Placing the unit in MODE 4 removes all requirements for OPERABILITY of the protection channels and actuation functions. In this MODE, the unit does not have analyzed transients or conditions that require the explicit use of the protection functions noted above.

BASES

ACTIONS

G.1, G.2.1 and G.2.2 (continued)

The Required Actions are modified by a Note that allows one train to be bypassed for up to 8 hours for surveillance testing provided the other train is OPERABLE. This allowance is based on the reliability analysis (Ref. 7) assumption that 8 hours is the average time required to perform channel surveillance.

H.1 and H.2

Condition H applies to the automatic actuation logic and actuation relays for the Feedwater Isolation Function.

This action addresses the train orientation of the relay logic and the actuation relays for this Function. If one train is inoperable, 6 hours are allowed to restore the train to OPERABLE status or the unit must be placed in MODE 3 within the following 6 hours unless the plant can be placed outside of the Applicable MODE or Conditions by other means (e.g., shutting all MBFPDVs or MBFRVs and associated bypass valves). The Completion Time for restoring a train to OPERABLE status is reasonable considering that there is another train OPERABLE, and the low probability of an event occurring during this interval. The allowed Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging unit systems. These Functions are no longer required in MODE 3. Placing the unit in MODE 3 removes all requirements for OPERABILITY of the protection channels and actuation functions. In this MODE, the unit does not have analyzed transients or conditions that require the explicit use of the protection functions noted above.

The Required Actions are modified by a Note that allows one train to be bypassed for up to 8 hours for surveillance testing provided the other train is OPERABLE. This allowance is based on the reliability analysis (Ref. 7) assumption that 8 hours is the average time required to perform channel surveillance.

BASES

ACTIONS (continued)

I.1, I.2 and J.1

Condition I applies to the AFW pump start on trip of either Main Boiler Feedwater pump.

The OPERABILITY of the AFW System must be assured by allowing automatic start of the AFW System pumps. The single channel associated with each operating MBFP will start both motor driven AFW pumps. However, there is no single failure tolerance for this Function unless both MBFPs are operating. Therefore, when a channel is inoperable, Required Action I.1, verifies that one channel associated with an operating MBFP is OPERABLE to ensure that there is no loss of function. Otherwise, entry into LCO 3.0.3 is required. If both MBFPs are operating, Required Action I.2 allows 48 hours to restore redundancy by requiring one channel associated with each operating MBFP to be OPERABLE. Continued operating without redundant channels when only one MBFP is operating is acceptable because this is a backup method for starting AFW and other Functions, in particular SG Water Level – Low Low, provide the primary protection against a loss of heat sink.

If the function cannot be returned to an OPERABLE status, 6 hours are allowed by Required Action J.1 to place the unit in MODE 3. The allowed Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging unit systems. In MODE 3, the unit does not have any analyzed transients or conditions that require the explicit use of the protection function noted above.

K.1, K.2.1 and K.2.2

Condition K applies to the Pressurizer Pressure interlock.

With one or more channels inoperable, the operator must verify that the interlock is in the required state for the existing unit condition. This action manually accomplishes the function of the interlock. Determination must be made within 1 hour. The 1 hour Completion Time is equal to the time allowed by LCO 3.0.3 to

BASES

ACTIONS

K.1, K.2.1 and K.2.2 (continued)

initiate shutdown actions in the event of a complete loss of ESFAS function. If the interlock is not in the required state (or placed in the required state) for the existing unit condition, the unit must be placed in MODE 3 within the next 6 hours and MODE 4 within the following 6 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems. Placing the unit in MODE 4 removes all requirements for OPERABILITY of this interlock.

SURVEILLANCE REQUIREMENTS

The SRs for each ESFAS Function are identified by the SRs column of Table 3.3.2-1.

A Note has been added to the SR Table to clarify that Table 3.3.2-1 determines which SRs apply to which ESFAS Functions.

Note that each channel of process protection supplies both trains of the ESFAS. When testing an individual channel, the SR is not met until both train A and train B logic are tested. The CHANNEL CALIBRATION and COTs are performed in a manner that is consistent with the assumptions used in the setpoint methodology described in Reference 6.

SR 3.3.2.1

Performance of the CHANNEL CHECK once every 12 hours ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the two instrument channels could be an

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.2.1 (continued)

indication of excessive instrument drift in one of the channels or of something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the unit staff, based on a combination of the channel instrument uncertainties, including indication and reliability. If a channel is outside the criteria, it may be an indication that the sensor or the signal processing equipment has drifted outside its limit.

The Frequency is based on operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal checks of channels during normal operational use of the displays associated with the LCO required channels.

SR 3.3.2.2

SR 3.3.2.2 is the performance of an ACTUATION LOGIC TEST. The relay logic is tested every 31 days on a STAGGERED TEST BASIS. The train being tested is placed in the bypass condition, thus preventing inadvertent actuation. All possible logic combinations are tested for each protection function required in Table 3.3.2-1. In addition, the master relay is tested. This verifies that the logic modules are OPERABLE and that there is a voltage signal path to the master relay coils. The Frequency of every 31 days on a STAGGERED TEST BASIS is adequate. It is based on industry operating experience, considering instrument reliability and operating history data.

SR 3.3.2.3

SR 3.3.2.3 is the performance of a MASTER RELAY TEST. The MASTER RELAY TEST is the energizing of the master relay, verifying contact operation and a low voltage continuity check of the slave relay coil. Upon master relay contact operation, a low voltage

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.2.3 (continued)

is supplied to the slave relay coil. This voltage is insufficient to pick up the slave relay, but large enough to demonstrate signal path continuity. This test is performed every 31 days on a STAGGERED TEST BASIS. The time allowed for the testing (8 hours) and the surveillance interval are justified in Reference 7.

SR 3.3.2.4

SR 3.3.2.4 is the performance of a COT.

A COT is performed on each required channel to ensure the entire channel (with the exception of the transmitter sensing device) will perform the intended Function. Setpoints must be found within the calibration acceptance criteriea.

The "as found" and "as left" values must also be recorded and reviewed. The difference between the current "as found" values and the previous test "as left" values must be consistent with the drift allowance used in the setpoint methodology. The setpoint shall be left set consistent with the assumptions of the current unit specific setpoint methodology (Ref. 6).

The Frequency of 92 days is justified in Reference 7.

SR 3.3.2.5

SR 3.3.2.5 is the performance of a SLAVE RELAY TEST. The SLAVE RELAY TEST is the energizing of the slave relays. Contact operation is verified in one of two ways. Actuation equipment that may be operated in the design mitigation MODE is either allowed to function, or is placed in a condition where the circuit operation can be verified without operation of the equipment. Actuation equipment that may not be operated in the design mitigation MODE is prevented from operation. Alternately, contact operation may be verified by a continuity check of the circuit containing the slave relay. This test is performed every

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.2.5 (continued)

24 months. The Frequency is adequate, based on industry operating experience, considering instrument reliability and operating history data.

SR 3.3.2.6

SR 3.3.2.6 is the performance of a TADOT. This test is a check of the Manual Actuation Functions and AFW pump start on trip of either MBFW pump or loss of offsite power (non SI). It is performed every 24 months. Each Manual Actuation Function is tested up to, and including, the master relay coils. In some instances, the test includes actuation of the end device (i.e., pump starts, valve cycles, etc.). The Frequency is adequate, based on industry operating experience and is consistent with the typical refueling cycle. The SR is modified by a Note that excludes verification of setpoints during the TADOT for manual initiation Functions. The manual initiation Functions have no associated setpoints.

SR 3.3.2.7

SR 3.3.2.7 is the performance of a CHANNEL CALIBRATION.

A CHANNEL CALIBRATION is performed every 24 months, or approximately at every refueling. CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to measured parameter within the necessary range and accuracy.

CHANNEL CALIBRATIONS must be performed consistent with the assumptions of the unit specific setpoint methodology (Ref. 6). The difference between the current "as found" values and the previous test "as left" values must be consistent with the drift allowance used in the setpoint methodology.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.2.7 (continued)

The Frequency of 24 months is based on the assumption of an 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint methodology.

This SR is modified by a Note stating that this test should include verification that the time constants are adjusted to the prescribed values where applicable.

REFERENCES

1. FSAR, Chapter 6.
2. FSAR, Chapter 7.
3. FSAR, Chapter 14.
4. IEEE-279-1968.
5. 10 CFR 50.49.
6. Engineering Standards Manual IES-3 and IES-3B, Instrument Loop Accuracy and Setpoint Calculation Methodology (IP3)
7. WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990.
8. Consolidated Edison Company of New York, Inc. Indian Point Nuclear Generating Station Unit No. 3 Plant Manual Volume VI: Precautions, Limitations, and Setpoints, March 1975.

B 3.3 INSTRUMENTATION

B 3.3.3 Post Accident Monitoring (PAM) Instrumentation

BASES

BACKGROUND

The primary purpose of the PAM instrumentation is to display unit variables that provide information required by the control room operators during accident situations. This information provides the necessary support for the operator to take the manual actions for which no automatic control is provided and that are required for safety systems to accomplish their safety functions for Design Basis Accidents (DBAs).

The OPERABILITY of the accident monitoring instrumentation ensures that there is sufficient information available on selected unit parameters to monitor and to assess unit status and behavior following an accident.

The availability of accident monitoring instrumentation is important so that responses to corrective actions can be observed and the need for, and magnitude of, further actions can be determined. These essential instruments are identified by unit specific documents (Ref. 1) addressing the recommendations of Regulatory Guide 1.97 (Ref. 2) as required by Supplement 1 to NUREG-0737 (Ref. 3).

The instrument channels required to be OPERABLE by this LCO include two classes of parameters identified during unit specific implementation of Regulatory Guide 1.97. The instruments governed by this LCO are the Type A and Category I variables which are defined as follows:

<u>Type A variables</u> are included in this LCO because they provide the primary information required for the control room operator to take specific manually controlled actions for which no automatic control is provided, and that are required for safety systems to accomplish their safety functions for DBAs.

BASES

BACKGROUND (continued)

Category I variables are the key variables deemed risk significant because they are needed to:

- Determine whether other systems important to safety are performing their intended functions;
- Provide information to the operators that will enable them to determine the likelihood of a gross breach of the barriers to radioactivity release; and
- Provide information regarding the release of radioactive materials to allow for early indication of the need to initiate action necessary to protect the public, and to estimate the magnitude of any impending threat.

These key variables are identified by the unit specific Regulatory Guide 1.97 analyses (Ref. 1). These analyses identify the unit specific Type A and Category I variables and provide justification for deviating from the NRC proposed list of Category I variables.

The specific instrument Functions listed in Table 3.3.3-1 are discussed in the LCO section.

APPLICABLE SAFETY ANALYSES

The PAM instrumentation ensures the operability of Regulatory Guide 1.97 Type A and Category I variables so that the control room operating staff can:

- Perform the diagnosis specified in the emergency operating procedures (these variables are restricted to preplanned actions for the primary success path of DBAs), e.g., loss of coolant accident (LOCA);
- Take the specified, pre-planned, manually controlled actions, for which no automatic control is provided, and that are required for safety systems to accomplish their safety function;

BASES

APPLICABLE SAFETY ANALYSES (continued)

- Determine whether systems important to safety are performing their intended functions;
- Determine the likelihood of a gross breach of the barriers to radioactivity release;
- Determine if a gross breach of a barrier has occurred; and
- Initiate action necessary to protect the public and to estimate the magnitude of any impending threat.

PAM instrumentation that meets the definition of Type A in Regulatory Guide 1.97 satisfies Criterion 3 of 10 CFR 50.36. Category I, non-Type A, instrumentation must be retained in TS because it is intended to assist operators in minimizing the consequences of accidents. Therefore, Category I, non-Type A, variables are important for reducing public risk and therefore, meet Criterion 4 of 10 CFR 50.36.

LCO

The PAM instrumentation LCO provides OPERABILITY requirements for Regulatory Guide 1.97 Type A monitors, which provide information required by the control room operators to perform certain manual actions specified in the unit Emergency Operating Procedures. These manual actions ensure that a system can accomplish its safety function, and are credited in the safety analyses. Additionally, this LCO addresses Regulatory Guide 1.97 instruments that have been designated Category I, non-Type A.

The OPERABILITY of the PAM instrumentation provides information about selected unit parameters to monitor and assess unit status following an accident. This capability is consistent with the recommendations of Reference 1. This LCO requires OPERABILITY of only one channel of each Type A and Category I variable. The additional channels of each Type A and Category I instrument described in Reference 1 and needed to meet Reference 2 requirements for single failure tolerance and channel diversity are controlled administratively.

BASES

LCO (continued)

Table 3.3.3-1 provides a list of all Type A and Category I variables identified by the IP3 Regulatory Guide 1.97 analyses, as amended by the NRC's SER Reference 1.

Type A and Category I variables are required to meet Regulatory Guide 1.97 Category I (Ref. 2) design and qualification requirements for seismic and environmental qualification, utilization of emergency standby power, immediately accessible display, continuous readout, and recording of display.

Requirements for single failure tolerance and channel diversity are controlled administratively.

The Safety Parameter Display System (SPDS) is provided to the Control Room to continuously displays information from which plant status can be assessed. The SPDS consists of the Critical Functions Monitoring System (CFMS) and the Qualified Safety Parameters Display System (QSPDS). The CFMS displays and alarms critical safety functions (actions which preserve integrity of one or more physical barriers against radiation) in the Control Room and the emergency response facilities. The CFMS is a redundant computer system not designed to seismic and electrical class 1E criteria. The QSPDS is qualified to seismic and electrical class 1E standards (Ref. 4). Note that the Qualified Safety Parameter Display System (QSPDS) is fully qualified to display and record Category 1 instrumentation as recommended by Regulatory Guide 1.97, Rev. 3 (Ref. 1).

Listed below are discussions of the specified instrument Functions listed in Table 3.3.3-1.

1. <u>Neutron Flux</u>

Neutron Flux indication covering full range of flux that may occur post accident is provided to verify reactor shutdown. Neutron flux is used for accident diagnosis, verification of subcriticality, and diagnosis of positive reactivity insertion.

BASES

LCO (continued)

To satisfy these requirements, an Excore Neutron Flux Detection System consisting of two detectors (N38, N39) provides two channels of neutron flux indication capable of providing indication from the source range to 100% RTP. Either one of these channels is required to be OPERABLE to satify requirements of this LCO. The Excore Neutron Flux Detection System is an indication only system that displays on the QSPDS in the Control Room. Redundancy for this function is provided by the source range, intermediate range and power range instruments of the Nuclear Instrumentation System.

2, 3. Reactor Coolant System (RCS) Hot and Cold Leg Temperatures (Wide Range)

RCS Hot and Cold Leg Temperatures are Category I variables required for verification of core cooling and long term surveillance. RCS cold leg temperature is used in conjunction with RCS hot leg temperature and steam gnerator pressure to verify the unit conditions necessary to establish natural circulation in the RCS.

This LCO is satisfied by the OPERABILITY of any one hot leg instrument and any one cold leg instrument from the following list:

Hot Leg Loop No. 1 (T413A)	Cold Leg Loop No. 1 (T413B)
Hot Leg Loop No. 2 (T423A)	Cold Leg Loop No. 2 (T423B)
Hot Leg Loop No. 3 (T433A)	Cold Leg Loop No. 3 (T433B)
Hot Leg Loop No. 4 (T443A)	Cold Leg Loop No. 4 (T443B)

Redundancy for the Hot Leg RCS Temperature is provided by the core exit thermocouples (Functions 18, 19, 20 and 21) which is considered a diverse variable for the RCS Hot Leg indication. Redundancy for the Cold Leg RCS Temperature is provided by Steam Generator Pressure (Function 15).

4. Reactor Coolant System Pressure (Wide Range)

RCS wide range pressure is a Category I variable required for verification of core cooling and RCS integrity long term surveillance.

BASES

LCO (continued)

RCS pressure is used to verify closure of manually closed pressurizer spray line valves and pressurizer power operated relief valves (PORVs). In addition, RCS pressure is used for determining RCS subcooling margin. RCS subcooling margin will allow termination of SI, if still in progress, or reinitiation of SI if it has been stopped. RCS pressure can also be used:

- to determine whether to terminate actuated SI or to reinitiate stopped SI;
- to determine when to reset SI and shut off low head SI;
- to manually restart low head SI;
- as reactor coolant pump (RCP) trip criteria; and
- to make a determination on the nature of the accident in progress and where to go next in the procedure.

RCS subcooling margin is also used for unit stabilization and cooldown control.

RCS pressure is also related to three decisions about depressurization. They are:

- to determine whether to proceed with primary system depressurization;
- to verify termination of depressurization; and
- to determine whether to close accumulator isolation valves during a controlled cooldown/depressurization.

RCS pressure is also used to determine whether to operate the pressurizer heaters.

RCS pressure is a Type A variable because the operator uses this indication to monitor the depressurization of the RCS following a steam generator tube rupture (SGTR) or small break LOCA. Operator actions to maintain a controlled cooldown, such as adjusting steam generator (SG) pressure or level, would use this

BASES

LCO (continued)

indication. Furthermore, RCS pressure is one factor that may be used in decisions to terminate RCP operation.

The LCO requirement for 1 channel of RCS Pressure (wide range) indication is satisfied by either pressure transmitter designated PT-402 or PT-403. Normal control room indication or recorders or displays on the QSPDS in the Control Room will satisfy this requirement.

Redundancy for RCS Pressure (wide range) indication is provided by the RCS 0-3000 psig pressure gauge which is located in an area accessible to plant operators. Additionally, pressure transmitters used to monitor pressurizer pressure (PT-455, PT-456, PT-457 and PT-474) for the range of 1700-2500 psig are available.

5. Reactor Vessel Water Level

Reactor Vessel Water Level is required for verification and long term surveillance of core cooling. It is also used for accident diagnosis and to determine reactor coolant inventory adequacy.

This requirement is satisfied by either of the two channels of the Reactor Vessel Level Indicating System (RVLIS). The RVLIS automatically compensate for variations in fluid density as well as for the effects of reactor coolant pump operation. The collapsed level represents the amount of liquid mass that is in the reactor vessel. Measurement of the collapsed water level is selected because it is a direct indication of the water inventory. The level instrumentation is divided into the full range and the dynamic range in order to measure level under all conditions. The full range gives level indication from the bottom of the reactor vessel to the top of the reactor head during natural circulation conditions. The dynamic range gives indication of reactor vessel liquid level for any combination of running RCP's.

6,7. Containment Water Level (Wide Range) and Recirculation Sump Level

Containment Water Level is required for verification and long term surveillance of RCS integrity.

BASES

LCO (continued)

Containment Water Level is used to determine:

- containment level accident diagnosis; and
- when to begin the recirculation procedure.

The LCO requirement for 1 channel of Containment Recirculation sump water level indication is satisfied by either level transmitter designated LT-1251 or LT-1252. The LCO requirement for 1 channel of Containment water level (wide range) indication is satisfied by either level transmitter designated LT-1253 and LT-1254. Normal control room indication will satisfy this requirement.

The refueling water storage tank level (Function 17) provides the diverse variable for measurement for the containment water level. Additionally, 2 channels of containment sump water level indication are available.

8. <u>Containment Pressure (Wide Range)</u>

Containment Pressure (Wide Range) is required for verification of need for and effectiveness of containment spray and fan cooler units.

The LCO requirements for 1 channel of Containment pressure indication is satisfied by pressure transmitters designated PT-1421 or PT-1422. Normal control room indication will satisfy this requirement. Additional containment pressure instrumentation, PT-948A, B & C and PT-949A, B & C, provide a diverse means of establishing containment pressure.

9. <u>Automatic Containment Isolation Valve Position</u>

CIV Position is provided for verification of Containment OPERABILITY and Phase A and Phase B isolation.

When used to verify Phase A and Phase B isolation, the important information is the isolation status of the containment penetrations. The LCO requires one channel of valve closed

BASES

LCO (continued)

position indication in the control room (or at local control stations for valves without control room indication) to be OPERABLE for each containment penetration flow path. If a normally active CIV is known to be closed and deactivated, position indication is not needed to determine status. Therefore, the position indication for valves in this state is not required to be OPERABLE.

Note (a) to the Required Channels states that the Function is not required for isolation valves whose associated penetration is isolated by at least one closed and deactivated automatic valve, closed manual valve, blind flange, or check valve.

Note that non-automatic containment isolation valves are not provided with position indication. As described in the Bases for LCO 3.6.3, "Containment Isolation Valves, containment isolation valves classified as essential and non-automatic are maintained in the open position and are closed after the initial phases of an accident. Emergency procedures are utilized to control the closing of these valves. Non-essential containment isolation valves are maintained in the closed position and may be opened, if necessary, for plant operation and for only as long as necessary to perform the intended function, under administrative controls described in the Bases for LCO 3.6.3.

10. Containment Area Radiation (High Range)

Containment Area Radiation is provided to monitor for the potential of significant radiation releases and to provide release assessment for use by operators in determining the need to invoke site emergency plans. The LCO requirement for 1 channel of Containment Area Radiation (high range) monitoring is satisfied by radiation monitors designated R-25 or R-26.

11. Containment Hydrogen Monitors

Hydrogen Monitors are provided to detect high hydrogen concentration conditions that represent a potential for containment breach from a hydrogen explosion. This variable is also important in verifying the adequacy of mitigating actions.

BASES

LCO (continued)

The LCO requirements for 1 channel of Containment Hydrogen monitoring is satisfied by either containment hydrogen sampling monitor designated HCMC-A or HCMC-B. Hydrogen monitor OPERABILITY requires that the associated containment fan cooler unit (FCU) is OPERABLE. HCMC-A is associated with FCU 32 or 35 and HCMC-B is associated with FCU 31 or 33 or 34.

12. <u>Pressurizer Level</u>

Pressurizer Level is used to determine whether to terminate SI, if still in progress, or to reinitiate SI if it has been stopped. Knowledge of pressurizer water level is also used to verify that the unit is maintained in a safe shutdown condition.

The LCO requirements for 2 channels of pressurizer level indication is satisfied by any two of the level instruments designated LT-459, LT-460 and LT-461.

13, 14. <u>Steam Generator Water Level (Wide Range and Narrow Range)</u>

SG Water Level is required to monitor operation of decay heat removal via the SGs.

Each Steam Generator (SG) contains 4 transmitters that indicate SG water level. Three transmitters per SG indicate narrow range level which is a span that begins at the top of the tube bundles up to the moisture separator. The remaining level transmitter, the wide range instrument, covers the span from the bottom tube sheet up to the moisture separator.

Requirements for steam generator water level indication assume that two of the four steam generators are required for heat removal.

Wide range SG water level is a Category I, Type A variable used to determine if the SG's are being maintained as an adequate heat sink for decay heat removal. The LCO requirement for 2 channels of wide range water level is satisfied by any two instruments designated LT-417D, LT-427D, LT-437D, and LT-447D.

BASES

LCO (continued)

Narrow range SG water level is a Category I, Type A variable used to determine if the SG's are being maintained as an adequate heat sink for decay heat removal and to maintain the SG level and prevent overfill. It is also used to determine whether SI should be terminated and may be used to diagnose an SG tube rupture event. The LCO requirements for 2 channels of narrow range SG water level is satisfied by any 1 instrument from any two different SGs such that all four SGs have at least one wide range or narrow range instrument:

SG 31	SG 32	SG 33	SG 34
LT-417A	LT-427A	LT-437A	LT-447A
LT-417B	LT-427B	LT-437B	LT-447B
LT-417C	LT-427C	LT-437C	LT-447C

15. Steam Generator Pressure

Each SG contains 3 transmitters that indicate SG pressure. Requirements for steam generator pressure indication assume that two of the four steam generators are required for heat removal. Requiring 1 channel per steam generator of SG pressure provides indication for all SGs.

SG pressure is a Category I, Type A variable used to determine if a high energy secondary line rupture occurred and which steam generator is faulted. SG pressure is also used as diverse indication of RCS cold leg temperature for natural circulation determination.

The LCO requirements for 1 channel per steam generator of pressure indication is satisfied by any 1 indication from the following instruments for each of the four SGs:

SG 31	SG 32	2SG 33	SG 34
PT-419A	PT-429A	PT-439A	PT-449A
PT-419B	PT-429B	PT-439B	PT-449B
PT-419C	PT-429C	PT-439C	PT-449C

BASES

LCO (continued)

16. Condensate Storage Tank (CST) Level

CST Level is provided to ensure water supply for auxiliary feedwater (AFW). The CST provides the ensured safety grade water supply for the AFW System.

CST Level is a Type A variable because the control room indication is the primary indication used by the operator.

The DBAs that require AFW are the loss of electric power, steam line break (SLB), and small break LOCA.

The CST is the initial source of water for the AFW System. However, as the CST is depleted, manual operator action is necessary to replenish the CST or align suction to the AFW pumps to city water.

The LCO requirement for 1 channel of CST level indication is satisfied by either level transmitter designated LT-1128 or LT-1128A. Normal control room indication or displays on the QSPDS in the Control Room will satisfy this requirement. Diverse indication of CST level can be derived from auxiliary feedwater suction pressure indication.

17. Refueling Water Storage Tank (RWST) Level Alarm

Following a LOCA, switchover from the injection phase to the recirculation phase must occur before the RWST empties to prevent damage to the pumps and a loss of cooling capability. For similar reasons, switchover must not occur before there is sufficient water in the containment to support recirculation pump suction. Furthermore, early switchover must not occur to ensure that sufficient borated water is injected from the RWST. The IP3 ESFAS design does not include automatic switchover from the safety injection mode to the recirculation mode of operation based on low level in the RWST coincident with a safety injection signal. This function is performed manually by the operator with the RWST level alarm (in conjunction with containment level) as the primary indicator for determining the time for the switchover. Therefore, RWST level alarms are Type A, Category 1 variable. Note that RWST

BASES

LCO (continued)

level indication is a Category 2 instrument as recommended in Regulatory Guide 1.97.

The RWST low-low level alarm setpoint has both upper and lower limits. The lower limit is selected to ensure switchover occurs before the RWST empties, to prevent ECCS pump damage. The high limit also ensures adequate water inventory in the containment sump to provide ECCS pump suction.

Requiring 2 channels of RWST level alarm ensures that the alarm function will be available assuming a single failure of one channel. Diverse indication of RWST level can be derived the post LOCA containment water level.

18, 19, 20, 21. Core Exit Temperature

Core Exit Temperature is required for verification and long term surveillance of core cooling. Core Exit Temperature is also used for unit stabilization and cooldown control. Core exit thermocouples also provide diverse indication for the RCS Hot Leg Temperature.

Four individual channels qualified to satisfy LCO requirements are provided in each quadrant of core. The LCO requirements for core exit thermocouple temperature indication are satisfied by any two channels in each of the 4 core quadrants (i.e., 2 channels per quadrant). Thermocouple readings are obtainable via the QSPDS and at a manually selected display unit in the control room.

Requiring 2 channels per core quadrant provides sufficient channels in each of the 4 quadrants to determine the core radial temperature gradient.

22. Main Steam Line (MSL) Radiation

The MSL radiation monitors are a Type A variable provided to allow detection of a gross secondary side radioactivity release and to provide a means to identify the faulted steam generator. The LCO requirements for MSL radiation indication are satisfied by one channel in each of the 4 MSLs using instruments designated R62A,

BASES

LCO (continued)

R62B, R62C, R62D. Steam generator narrow range level serves as diverse indication for the one monitor per loop provided.

23. Gross Failed Fuel Detector

The gross failed fuel detector is a Type A variable provided to allow determination of reactor coolant system radioactivity concentration. The LCO requires 1 OPERABLE channel and can be satisfied using either R-63A or R-63B.

24. RCS Subcooling

RCS subcooling margin is a Type A variable provided to determine whether to terminate actuated SI or to reinitiate stopped SI, to determine when to terminate reactor coolant pump operation, and for unit stabilization and cooldown control. RCS subcooling margin is calculated and displayed in the plant Qualified Safety Parameter Display System. Diverse indication is available using saturation pressure and steam tables.

APPLICABILITY

The PAM instrumentation LCO is applicable in MODES 1, 2, and 3. These variables are related to the diagnosis and pre-planned actions required to mitigate DBAs. The applicable DBAs are assumed to occur in MODES 1, 2, and 3. In MODES 4, 5, and 6, unit conditions are such that the likelihood of an event that would require PAM instrumentation is low; therefore, the PAM instrumentation is not required to be OPERABLE in these MODES.

ACTIONS

Note 1 has been added in the ACTIONS to exclude the MODE change restriction of LCO 3.0.4. This exception allows entry into the applicable MODE while relying on the ACTIONS even though the ACTIONS may eventually require unit shutdown. This exception is acceptable due to the passive function of the instruments, the operator's ability to respond to an accident using alternate instruments and methods, and the low probability of an event requiring these instruments.

BASES

ACTIONS (continued)

Note 2 has been added in the ACTIONS to clarify the application of Completion Time rules. The Conditions of this Specification may be entered independently for each Function listed on Table 3.3.3-1. The Completion Time(s) of the inoperable channel(s) of a Function will be tracked separately for each Function starting from the time the Condition was entered for that Function.

A.1

Condition A applies when one or more Functions have one inoperable required channel. Required Action A.1 requires restoring one channel in the Function(s) to OPERABLE status within 7 days. The Completion Time of 7 days is based on the relatively low probability of an event requiring PAM instrument operation and the availability of alternate means to obtain the required information. Continuous operation with a required channel inoperable in a Function is not acceptable because the alternate indications may not fully meet all performance qualification requirements applied to the PAM instrumentation. Therefore, requiring restoration of one inoperable channel of the Function limits the risk that the PAM Function will be in a degraded condition should an accident occur.

Condition A also applies when one channel of RWST low level alarm (Table 3.3.31-1, Function 17) is inoperable. Required Action A.1 requires restoring the inoperable channel to OPERABLE status within 7 days. The 7 day Completion Time for restoration of redundancy of the alarm function is needed because the IP3 ESFAS design does not include automatic switchover from the safety injection mode to the recirculation mode of operation based on low level in the RWST coincident with a safety injection signal. This function is performed manually by the operator with the RWST level alarm (in conjunction with containment sump level) as the primary indicator for determining the time for the switchover.

B.1

Condition B applies when the Required Action or associated Completion Time of Condition A are not met. Required Action B.1 requires entering the appropriate Condition referenced in

BASES

ACTIONS

B.1 (continued)

Table 3.3.3-1 for the channel immediately. The applicable Condition referenced in the Table is Function dependent. Each time an inoperable channel has not met any Required Action of Condition A, and the associated Completion Time has expired, Condition B is entered for that channel and provides for transfer to the appropriate subsequent Condition.

C.1 and C.2

If Condition B exists or if the Required Action and associated Completion Time of Conditions A are not met and Table 3.3.3-1 directs entry into Condition C, the unit must be brought to a MODE where the requirements of this LCO do not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and MODE 4 within 12 hours.

The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

D.1

Alternate means of monitoring neutron flux, condensate storage tank level, main steam line radiation, gross failed fuel, containment isolation valve position indications and containment area radiation are available. These alternate means may be used if the normal PAM channel cannot be restored to OPERABLE status within the allotted time. If these alternate means can be used, the Required Action is not to shut down the unit but rather to follow the directions of Specification 5.6.7, in the Administrative Controls section of the TS. The report provided to the NRC should discuss the alternate means available, describe the degree to which the alternate means are equivalent to the installed PAM channels, justify the areas in which they are not equivalent, and provide a schedule for restoring the normal PAM channels.

BASES

SURVEILLANCE REQUIREMENTS

A Note has been added to the SR Table to clarify that SR 3.3.3.1 and SR 3.3.3.3 apply to each PAM instrumentation Function in Table 3.3.3-1.

SR 3.3.3.1

Performance of the CHANNEL CHECK once every 31 days ensures that a gross instrumentation failure has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the two instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION. The high radiation instrumentation should be compared to similar unit instruments located throughout the unit.

Agreement criteria are determined by the unit staff, based on a combination of the channel instrument uncertainties, including isolation, indication, and readability. If a channel is outside the criteria, it may be an indication that the sensor or the signal processing equipment has drifted outside its limit. If the channels are within the criteria, it is an indication that the channels are OPERABLE.

As specified in the SR, a CHANNEL CHECK is only required for those channels that are normally energized.

The Frequency of 31 days is based on operating experience that demonstrates that channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the LCO required channels.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.3.2

A CHANNEL CALIBRATION is performed every 24 months, or approximately at every refueling. CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to measured parameter with the necessary range and accuracy. This SR is modified by a Note that excludes neutron detectors. The calibration method for neutron detectors is described in the Bases of LCO 3.3.1, "Reactor Trip System (RTS) Instrumentation." The Frequency is based on operating experience and consistency with the typical industry refueling cycle.

REFERENCES

1. Safety Evaluation: Conformance to Regulatory Guide 1.97, Revision 3, for Indian Point 3 (TAC No. 51099), dated April 3, 1991.
2. Regulatory Guide 1.97, Revision 3.
3. NUREG-0737, Supplement 1, "TMI Action Items."
4. FSAR, Section 7.

B 3.3 INSTRUMENTATION

B 3.3.4 Remote Shutdown

BASES

BACKGROUND

Remote Shutdown provides the control room operator with sufficient instrumentation and controls to place and maintain the unit in a safe shutdown condition from a location other than the control room. This capability is necessary to protect against the possibility that the control room becomes inaccessible. A safe shutdown condition is defined as MODE 3. With the unit in MODE 3, the Auxiliary Feedwater (AFW) System and the main steam safety valves (MSSVs) or the SG atmospheric dump valves (ADVs) can be used to remove core decay heat and meet all safety requirements. The long term supply of water for the AFW System and the ability to borate the Reactor Coolant System (RCS) from outside the control room allows extended operation in MODE 3.

If the control room becomes inaccessible, the operators can establish control at various local control stations and place and maintain the unit in MODE 3. Controls and transfer switches are operated locally at the switchgear, motor control panels, or other local stations. The unit automatically reaches MODE 3 following a unit shutdown and can be maintained safely in MODE 3 for an extended period of time.

The OPERABILITY of the local control and instrumentation functions ensures there is sufficient information available on selected unit parameters to place and maintain the unit in MODE 3 should the control room become inaccessible.

APPLICABLE SAFETY ANALYSES

Remote Shutdown is required to provide equipment at appropriate locations outside the control room to promptly shut down and maintain the unit in a safe condition in MODE 3.

The criteria governing the design and specific system requirements of the Remote Shutdown are located in 10 CFR 50, Appendix A, GDC 19 (Ref. 1).

BASES

APPLICABLE SAFETY ANALYSES (continued)

Remote Shutdown capability and requirements for remote shutdown are presented in Reference 2.

Remote Shutdown is considered an important contributor to the reduction of unit risk to accidents and as such meets Criterion 4 of CFR 50.36.

LCO

The Remote Shutdown LCO provides the OPERABILITY requirements of the instrumentation and controls necessary to place and maintain the unit in MODE 3 from a location other than the control room. The instrumentation and controls required are listed in Bases Table B 3.3.4-1.

The controls, instrumentation, and transfer switches are required for:

- Core reactivity control (initial and long term);
- RCS pressure control;
- Decay heat removal via the AFW System and the MSSVs or SG ADVs;
- RCS inventory control via charging flow; and
- Safety support systems for the above Functions, including service water, component cooling water, and onsite power, including the diesel generators.

A Function of a Remote Shutdown is OPERABLE if all instrument and control channels needed to support the Remote Shutdown Function are OPERABLE. In some cases, Table 3.3.4-1 may indicate that the required information or control capability is available from several alternate sources. In these cases, the Function is OPERABLE as long as one channel of any of the alternate information or control sources is OPERABLE.

BASES

LCO (continued)

The remote shutdown instrument and control circuits covered by this LCO do not need to be energized to be considered OPERABLE. This LCO is intended to ensure the instruments and control circuits will be OPERABLE if unit conditions require that the plant is shutdown from a location other than the control room.

APPLICABILITY

The Remote Shutdown LCO is applicable in MODES 1, 2, and 3. This is required so that the unit can be placed and maintained in MODE 3 for an extended period of time from a location other than the control room.

This LCO is not applicable in MODE 4, 5, or 6. In these MODES, the facility is already subcritical and in a condition of reduced RCS energy. Under these conditions, considerable time is available to restore necessary instrument control functions if control room instruments or controls become unavailable.

ACTIONS

Note 1 is included which excludes the MODE change restriction of LCO 3.0.4. This exception allows entry into an applicable MODE while relying on the ACTIONS even though the ACTIONS may eventually require a unit shutdown. This exception is acceptable due to the low probability of an event requiring remote shutdown and because the equipment can generally be repaired during operation without significant risk of spurious trip.

Note 2 has been added to the ACTIONS to clarify the application of Completion Time rules. Separate Condition entry is allowed for each Function listed on Table 3.3.4-1. The Completion Time(s) of the inoperable channel(s)/train(s) of a Function will be tracked separately for each Function starting from the time the Condition was entered for that Function.

A.1

Condition A addresses the situation where one or more required Remote Shutdown Functions are inoperable. This includes any

BASES

ACTIONS

A.1 (continued)

Function listed in Table 3.3.4-1, as well as the control and transfer switches.

The Required Action is to restore the required Function to OPERABLE status within 30 days. The Completion Time is based on operating experience and the low probability of an event that would require evacuation of the control room.

B.1 and B.2

If the Required Action and associated Completion Time of Condition A is not met, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

The following Surveillance Requirements are applied to each of the remote shutdown function in Bawes Table B 3.3.4-1, as appropriate.

SURVEILLANCE REQUIREMENTS

The following Surveillance Requirements are applied to each of the remote shutdown functions in Table B 3.3.4-1, as appropriate.

SR 3.3.4.1

Performance of the CHANNEL CHECK once every 31 days ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the two instrument channels could be an

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.4.1 (continued)

indication of excessive instrument drift in one of the channels or of something even more serious. CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying that the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the unit staff, based on a combination of the channel instrument uncertainties, including indication and readability. If the channels are within the criteria, it is an indication that the channels are OPERABLE. If a channel is outside the criteria, it may be an indication that the sensor or the signal processing equipment has drifted outside its limit.

As specified in the Surveillance, a CHANNEL CHECK is only required for those channels which are normally energized.

The Frequency of 31 days is based upon operating experience which demonstrates that channel failure is rare. The CHANNEL CHECK supplements less formal checks of channels during normal operational use of the displays associated with the LCO required channels.

SR 3.3.4.2

SR 3.3.4.2 verifies each required Remote Shutdown control circuit and transfer switch performs the intended function. This verification is performed locally. Operation of the equipment is not necessary. The Surveillance can be satisfied by performance of a continuity check. This will ensure that if the control room becomes inaccessible, the unit can be placed and maintained in MODE 3 from the local control stations. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. (However, this Surveillance is not required to be performed only during a unit outage.) Operating experience demonstrates that remote shutdown control channels

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.4.2 (continued)

usually pass the Surveillance test when performed at the 24 month Frequency.

SR 3.3.4.3

CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. The test verifies that the channel responds to a measured parameter within the necessary range and accuracy.

The Frequency of 24 months is based upon operating experience and consistency with the typical industry refueling cycle.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 19.

2. FSAR, Section 7.7.3.

Table B 3.3.4-1 (page 1 of 1)
Remote Shutdown Instrumentation and Controls

FUNCTION/INSTRUMENT OR CONTROL PARAMETER	REQUIRED NUMBER OF FUNCTIONS
1. Reactivity Control	
a. Source Range Neutron Flux	1
b. Reactor Trip Breaker Position	1 per trip breaker
c. Manual Reactor Trip	2
2. Reactor Coolant System (RCS) Pressure Control	
a. Pressurizer Pressure or RCS Wide Range Pressure	1
b. Pressurizer Heaters	1
3. Decay Heat Removal via Steam Generators (SGs)	
a. RCS Hot Leg Temperature (loop 31)	1
b. RCS Cold Leg Temperature (loop 31)	1
c. AFW Controls	1
d. SG Pressure	1
e. SG Level	1
4. RCS Inventory Control	
a. Pressurizer Level	1
b. Charging Pump Controls	1

B 3.3 INSTRUMENTATION

B 3.3.5 Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation

BASES

BACKGROUND

The DGs provide a source of emergency power when offsite power is either unavailable or is insufficiently stable to allow safe unit operation. Undervoltage protection will generate a DG start if a loss of voltage or degraded voltage condition occurs on a 480 V bus.

Two undervoltage relays are provided on each 480 V bus for detecting a bus undervoltage. Either of the two relays is sufficient to satisfy requirements for the 480 V bus undervoltage Function even though the failure of the one remaining undervoltage relay could result in the failure of one DG to start because there is redundancy in the number of EDGs available. The two undervoltage relays are combined in a one-out-of-two logic per bus to generate an undervoltage signal. The allowable value and trip setpoint for this function is established in accordance with Reference 3. Actuation of these relays will trip the bus supply breaker, initiate load shedding, start the DG, and initiate load sequencing. There is no explicit time delay for this function because the undervoltage protection devices are induction type disc relays. Therefore, the time to actual trip will decrease as a function of voltage decrease below the setpoint.

Two degraded voltage relays are provided on each 480 V bus for detecting degraded bus voltage. The relays are combined in a two-out-of-two logic per bus (to prevent spurious actuation). The allowable value and trip setpoint for this function is established in accordance with Reference 3. Function actuation includes a time delay of ≤ 10 seconds if a coincident SI signal indicates accident conditions exist and a time delay of ≤ 45 seconds if no SI signal is generated (i.e., non-accident condition). These time delays ensure proper coordination with plant electrical transients (e.g. large motor starts, fast transfers, etc.). Actuation of these relays will trip the bus supply breaker, which will in turn actuate the undervoltage relays.

BASES

BACKGROUND (Continued)

The LOP start actuation is described in FSAR, Section 8.2 (Ref. 1).

Trip Setpoints and Allowable Values

Technical Specification Allowable Values are determined based on the relationship between an analytical limit and a calculated trip setpoint. A detailed discussion of the relative position of the safety limit, analytical limit, allowable value and the trip setpoint with respect to the normal plant operation point is presented in the Bases of LCO 3.3.1, Reactor Protection System (RPS) Instrumentation.

A detailed description of the methodology used to calculate the channel Allowable and bistable device, including their explicit uncertainties, is provided in Engineering Standards Manual IES-3 and IES-3B, Instrument Loop Accuracy and Setpoint Calculation Methodology (IP3) (Ref. 3).

APPLICABLE SAFETY ANALYSES

The LOP DG start instrumentation is required for the Engineered Safety Features (ESF) Systems to function in any accident with a loss of offsite power. Its design basis is that of the ESF Actuation System (ESFAS).

Accident analyses credit the loading of the DG based on the loss of offsite power during a loss of coolant accident (LOCA). The actual DG start has historically been associated with the ESFAS actuation. The DG loading has been included in the delay time associated with each safety system component requiring DG supplied power following a loss of offsite power.

The required channels of LOP DG start instrumentation, in conjunction with the ESF systems powered from the DGs, provide unit protection in the event of any of the analyzed accidents discussed in Reference 2, in which a loss of offsite power is assumed.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The delay times assumed in the safety analysis for the ESF equipment include the 10 second DG start delay, and the appropriate sequencing delay. The response times for ESFAS actuated equipment in LCO 3.3.2, "Engineered Safety Feature Actuation System (ESFAS) Instrumentation," include the appropriate DG loading and sequencing delay.

The LOP DG start instrumentation channels satisfy Criterion 3 of 10 CFR 50.36.

LCO

The LCO for LOP DG start instrumentation requires that 1 channel per bus of the undervoltage (480 V bus) Function and two channels per bus of the Degraded Voltage (480 V bus) Function must be OPERABLE in MODES 1, 2, 3 and 4 when the LOP DG start instrumentation supports safety systems associated with the ESFAS. In MODES 5 and 6, 1 channel per bus of the undervoltage (480 V bus) Function and two channels per bus of the Degraded Voltage (480 V bus) Function must be OPERABLE whenever the associated DG is required to be OPERABLE to ensure that the automatic start of the DG is available when needed.

APPLICABILITY

The LOP DG Start Instrumentation Functions are required in MODES 1, 2, 3, and 4 because ESF Functions are designed to provide protection in these MODES. Actuation in MODE 5 or 6 is required whenever the required DG must be OPERABLE so that it can perform its function on an LOP or degraded power to the vital bus.

ACTIONS

In the event a channel's Trip Setpoint is found nonconservative with respect to the Allowable Value, or the channel is found inoperable, then the function that channel provides must be declared inoperable and the LCO Condition entered for the particular protection function affected.

BASES

ACTIONS (continued)

Because the required channels are specified on a per bus basis, the Condition may be entered separately for each bus as appropriate.

A Note has been added in the ACTIONS to clarify the application of Completion Time rules. The Conditions of this Specification may be entered independently for each Function listed in the LCO. The Completion Time(s) of the inoperable channel(s) of a Function will be tracked separately for each Function starting from the time the Condition was entered for that Function.

A.1

Condition A applies to the LOP DG start Function with one required channel of the undervoltage function inoperable. Note that LCO 3.3.5 requires that only one of the two undervoltage (480 V bus) channels must be OPERABLE. Therefore, Condition A applies when there is no OPERABLE undervoltage (480 V bus) channel on one or more 480 volt bus(es).

If one required channel is inoperable or one or more 480 V buses, Required Action A.1 requires that channel to be restored to OPERABLE status within 1 hour.

The specified Completion Time of 1 hour to restore an undervoltage (480 V bus) channels to OPERABLE status is needed because this Condition represents a loss of the undervoltage DG starting Function for the associated DG. The 1 hour delay in declaring the DG inoperable is acceptable because of the low probability of an event occurring during this interval.

B.1

Condition B applies when one of the two required degraded voltage channels is inoperable on one or more 480 V bus. Required Action B.1 requires placing the inoperable channel in trip so that trip capability is restored to the 2 out of 2 logic used to initiate this Function. The 1 hour Completion Time takes into account the low probability of an event requiring an LOP start occurring during this interval.

BASES

ACTIONS (continued)

C.1

Condition C applies to each of the LOP DG start Functions when the Required Action and associated Completion Time for Condition A or B are not met. Condition C also applies when two channels of Degraded Voltage Function inoperable in one or more buses. In this Condition, Function trip capability is lost even if one of the channels is placed in trip as specified in Required Action B.1.

In these circumstances the Conditions specified in LCO 3.8.1, "AC Sources - Operating," or LCO 3.8.2, "AC Sources - Shutdown," for the DG made inoperable by failure of the LOP DG start instrumentation are required to be entered immediately. The actions of those LCOs provide for adequate compensatory actions to assure unit safety.

SURVEILLANCE REQUIREMENTS

SR 3.3.5.1

SR 3.3.5.1 is the performance of a TADOT. This test is performed every 31 days. The test checks trip devices that provide actuation signals directly, bypassing the analog process control equipment. The Frequency is based on the known reliability of the relays and controls and the multichannel redundancy available, and has been shown to be acceptable through operating experience.

SR 3.3.5.2

SR 3.3.5.2 is the performance of a CHANNEL CALIBRATION.

The setpoints, as well as the response to a loss of voltage and a degraded voltage test, shall include a single point verification that the trip occurs within the required time delay, as applicable.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.5.2 (continued)

A CHANNEL CALIBRATION is performed every 24 months for the undervoltage relay and every 18 months for the degraded voltage relay. CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to a measured parameter within the necessary range and accuracy.

The Frequency is based on operating experience and is justified by the assumption of the calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis (Ref. 3).

REFERENCES

1. FSAR, Section 8.2.

2. FSAR, Chapter 14.2.

3. Engineering Standards Manual IES-3 and IES-3B, Instrument Loop Accuracy and Setpoint Calculation Methodology (IP3).

B 3.3 INSTRUMENTATION

B 3.3.6 Containment Purge System and Pressure Relief Line Isolation Instrumentation

BASES

BACKGROUND

Containment purge system and pressure relief line isolation instrumentation closes the containment isolation valves in the Pressure Relief Line and the Containment Purge System. This action isolates the containment atmosphere from the environment to minimize releases of radioactivity in the event of an accident. The Containment Pressure Relief Line may be in use during reactor operation and the Containment Purge System may be in use with the reactor shutdown.

The Containment Purge System consists of the 36-inch containment purge supply and exhaust penetrations. The containment purge supply and exhaust penetrations each include two butterfly valves for isolation. The containment purge exhaust penetration includes two butterfly valves for isolation and can be aligned to discharge to the atmosphere through the plant vent either directly or through the Containment Purge Filter System (i.e., a filter bank with roughing, HEPA and charcoal filters).

The Containment Purge System is isolated when in Modes 1, 2, 3 and 4 in accordance with requirements established in LCO 3.6.3, Containment Isolation Valves. In Modes 5 and 6, the Containment Purge System may be used for containment ventilation. When open, the Containment Purge System isolation valves are automatically closed when high radiation levels are detected by the Containment Air Particulate Monitor (R-11) or Containment Radioactive Gas Monitor (R-12).

The Containment Purge System isolation capability is not the primary method for ensuring that 10 CFR 100 limits are not exceeded during a fuel handling event (Ref. 1). As specified in LCO 3.9.3, Containment Penetrations, the Containment Purge System is aligned to discharge through the Containment Purge Filter System during CORE ALTERATIONS or movement of irradiated fuel until the reactor has been shutdown for at least 550 hours. Purge path filtration during the first 550 hours following reactor shutdown ensures that the dose limit for a fuel handling

BASES

BACKGROUND (Continued)

accident of 75 rem to the thyroid (25 percent of the 10 CFR Part 100 limit of 300 rem) at the Exclusion Area Boundary (EAB) (i.e., site boundary) is not exceeded (Ref. 2).

The Containment Pressure Relief Line (i.e., Containment Vent) consists of a single 10-inch containment vent line that is used to handle normal pressure changes in the Containment when in Modes 1, 2, 3 and 4. The Containment Pressure Relief Line is equipped with three quick-closing butterfly type isolation valves, one inside and two outside the containment which isolate automatically as part of Safety Injection ESFAS signal (LCO 3.3.2, Function 1) and Containment Spray ESFAS signal (LCO 3.3.2, Function 2). Automatic isolation of the Containment Pressure Relief Line is also initiated when high radiation levels are detected by the Containment Air Particulate Monitor (R-11) or Containment Radioactive Gas Monitor (R-12).

The Containment Pressure Relief Line is isolated during CORE ALTERATIONS or movement of irradiated fuel during the first 550 hours following reactor shutdown as specified in LCO 3.9.3. Although the Containment Pressure Relief Line discharges to the atmosphere via the Containment Auxiliary Charcoal Filter System (i.e., a filter bank with roughing, HEPA and charcoal filters), the Containment Auxiliary Charcoal Filter System is not required to be tested in accordance with Specification 5.5.10, Ventilation Filter Test Program.

Both the Containment Purge supply and exhaust isolation valves (FCV-1170, FCV-1171, FCV-1172, and FCV-1173) and the containment pressure relief isolation valves (PCV-1190, PCV-1191, and PCV-1192) close when high radiation levels are detected by the Containment Air Particulate Monitor (R-11) or Containment Radioactive Gas Monitor (R-12). The Safety Injection ESFAS signal (LCO 3.3.2, Function 1) and Containment Spray ESFAS signal (LCO 3.3.2, Function 2) also cause closure of the Containment Purge isolation valves and the containment pressure relief isolation valves. Although not required to satisfy Technical Specification requirements, containment purge and containment pressure relief are also isolated when high radiation levels are detected in the plant vent.

BASES

APPLICABLE SAFETY ANALYSES

In MODE 1, 2, 3 or 4, Containment Purge System automatic isolation capability is not required because the Containment Purge System is isolated in accordance with the requirements of LCO 3.6.3, Containment Isolation Valves.

During CORE ALTERATIONS or movement of irradiated fuel in the containment, Containment Purge System automatic isolation capability is required because it provides for automatic containment isolation in response to a fuel handling accident. As specified in LCO 3.9.3, Containment Penetrations, the Containment Purge System is aligned to discharge through the Containment Purge Filter System during CORE ALTERATIONS or movement of irradiated fuel until the reactor has been shutdown for at least 550 hours. Purge path filtration during the first 550 hours following reactor shutdown ensures that the dose limit for a fuel handling accident of 75 rem to the thyroid (25 percent of the 10 CFR Part 100 limit of 300 rem) at the EAB (i.e., site boundary) is not exceeded (Ref. 2). Although Containment Purge System isolation capability is not required to meet 10 CFR Part 100 limits during a fuel handling accident, this function provides a backup to the filtering function assumed in the analysis and is required to provide containment isolation following the event.

In MODE 1, 2, 3 or 4, Containment Pressure Relief Line automatic isolation capability is required as part of the containment isolation function initiated by the Engineered Safety Feature Actuation System (ESFAS) Instrumentation required by LCO 3.3.2. Containment Pressure Relief Line automatic isolation when high radiation levels are detected by the Containment Air Particulate Monitor (R-11) or Containment Radioactive Gas Monitor (R-12) provides a backup to the closure initiated by the ESFAS system.

During CORE ALTERATIONS or movement of irradiated fuel in the containment, Containment Pressure Relief Line automatic isolation capability is not required because the Containment Pressure Relief Line is isolated as specified in LCO 3.9.3. The Containment Pressure Relief Line is isolated because the fuel

BASES

APPLICABLE SAFETY ANALYSES (continued)

handling accident analysis (References 1 and 2) credits filtration and not automatic isolation to ensure 10 CFR 100 limits are met. The Containment Auxiliary Charcoal Filter System which filters the Containment Pressure Relief Line is not required to be tested in accordance with Specification 5.5.10, Ventilation Filter Test Program.

The containment purge system and pressure relief line isolation instrumentation satisfies Criterion 3 of 10 CFR 50.36.

LCO

The LCO requirements ensure that the instrumentation listed in Table 3.3.6-1, is OPERABLE. This instrumentation is required to initiate automatic isolation of the Containment Purge System and the Containment Pressure Relief Line.

1. Automatic Actuation Logic and Actuation Relays

The LCO requires two trains of Automatic Actuation Logic and Actuation Relays OPERABLE to ensure that no single random failure can prevent automatic actuation.

Automatic Actuation Logic and Actuation Relays are required to be OPERABLE to support the Operability of all of the required functions that isolate the containment purge system and pressure relief line (i.e., gaseous and particulate radiation monitors (R-11 and R-12) and ESFAS SI and containment spray initiation signals). The term Automatic Actuation Logic and Actuation Relays applies to those portions of the circuit that are: 1) common to more than one channel in one train of a single function (i.e., the automatic actuation logic); or, 2) the initiating relay contacts in one train responsible for actuating the equipment and which are common to more than one channel of a single function and more than one function (i.e., the actuation relays). There are two trains of automatic actuation logic and actuation relays for the containment purge system and pressure relief line.

BASES

LCO (continued)

If one or more of the SI or Containment Spray Functions becomes inoperable in such a manner that only the Containment Purge Isolation Function is affected, the Conditions applicable to their SI and Containment Spray Functions need not be entered. The less restrictive Actions specified for inoperability of the Containment Purge System and Pressure Relief Line Isolation Functions specify sufficient compensatory measures for this case.

2. Containment Radiation Monitors

The LCO specifies two required channels of radiation monitors to ensure that the radiation monitoring instrumentation necessary to initiate Containment Purge System Isolation remains OPERABLE. The requirement for two channels is satisfied by the Containment Air Particulate Monitor (R-11) and the Containment Radioactive Gas Monitor (R-12). Allowable values and setpoints for these Functions are specified in the IP3 Offsite Dose Calculation Manual (Ref. 3).

Channel OPERABILITY involves more than OPERABILITY of the channel electronics. OPERABILITY may also require correct valve lineups, sample pump operation, and filter motor operation, as well as detector OPERABILITY, if these supporting features are necessary for trip to occur under the conditions assumed by the safety analyses.

3. ESFAS Function 1, Safety Injection, and ESFAS Function 2, Containment Spray Monitors

Refer to LCO 3.3.2, Functions 1 and 2, for all initiating Functions and requirements.

APPLICABILITY

In MODE 1, 2, 3 or 4, Containment Purge System automatic isolation capability is not required because the Containment Purge System is isolated in accordance with the requirements of LCO 3.6.3, Containment Isolation Valves.

BASES

APPLICABILITY (continued)

During CORE ALTERATIONS or movement of irradiated fuel in the containment, Containment Purge System automatic isolation Function 1, Automatic Actuation Logic and Actuation Relays, and Function 2, Containment Radiation, are required to be OPERABLE to ensure Containment Purge System isolation in response to a fuel handling accident.

In MODE 1, 2, 3 or 4, Containment Pressure Relief Line automatic isolation Function 1, Automatic Actuation Logic and Actuation Relays, and Function 3, ESFAS Safety Injection and ESFAS Containment Spray, are required as part of the containment isolation function initiated by the Engineered Safety Feature Actuation System (ESFAS) Instrumentation required by LCO 3.3.2. Containment Pressure Relief Line automatic isolation Function 2, Containment Radiation, is required as a backup to the closure initiated by the ESFAS system.

During CORE ALTERATIONS or movement of irradiated fuel in the containment, Containment Pressure Relief Line automatic isolation capability is not required because the Containment Pressure Relief Line is isolated as specified in LCO 3.9.3.

While in MODES 5 and 6 without fuel handling in progress, the containment purge system and pressure relief line isolation instrumentation need not be OPERABLE since the potential for radioactive releases is minimized and operator action is sufficient to ensure post accident offsite doses are maintained within the limits of 10 CFR 100.

ACTIONS

The most common cause of channel inoperability is outright failure or drift of the bistable or process module sufficient to exceed the tolerance allowed by unit specific calibration procedures. Typically, the drift is found to be small and results in a delay of actuation rather than a total loss of function. This determination is generally made during the performance of a COT, when the process instrumentation is set up for adjustment to bring it within specification. If the Trip Setpoint is less conservative than the tolerance specified by the

BASES

ACTIONS (continued)

calibration procedure, the channel must be declared inoperable immediately and the appropriate Condition entered.

A Note has been added to the ACTIONS to clarify the application of Completion Time rules. The Conditions of this Specification may be entered independently for each Function listed in Table 3.3.6-1. The Completion Time(s) of the inoperable channel(s)/train(s) of a Function will be tracked separately for each Function starting from the time the Condition was entered for that Function.

A.1

Condition A applies to the failure of either the R-11 or the R-12 radiation monitor channel. Since the two containment radiation monitors measure different parameters, failure of a single channel may result in delay of the radiation monitoring Function for certain events. However, 7 days is allowed to restore the affected channel because the containment radiation monitoring function is not the primary method or ensuring that 10 CFR limits are not exceed.

B.1

Condition B applies to all Containment Pressure Relief Line Isolation Functions and addresses the train orientation of these Functions. It also addresses the failure of both radiation monitoring channels, or the inability to restore a single failed channel to OPERABLE status in the time allowed for Required Action A.1.

If a train is inoperable, multiple channels are inoperable, or the Required Action and associated Completion Time of Condition A are not met, operation may continue as long as the Required Action for the applicable Conditions of LCO 3.6.3 is met for each valve made inoperable by failure of isolation instrumentation. A Note is added stating that Condition B is only applicable in MODE 1, 2, 3, or 4.

BASES

ACTIONS (continued)

C.1 and C.2

Condition C applies to all Containment Purge System Isolation Functions and addresses the train orientation of these Functions. It also addresses the failure of both radiation monitoring channels, or the inability to restore a single failed channel to OPERABLE status in the time allowed for Required Action A.1. If a train is inoperable, multiple channels are inoperable, or the Required Action and associated Completion Time of Condition A are not met, operation may continue as long as the Required Action to place and maintain Containment Purge System isolation valves in their closed position is met or the applicable Conditions of LCO 3.9.3, "Containment Penetrations," are met for each valve made inoperable by failure of isolation instrumentation. The Completion Time for these Required Actions is Immediately.

A Note states that Condition C is applicable during CORE ALTERATIONS and during movement of irradiated fuel assemblies within containment.

SURVEILLANCE REQUIREMENTS

A Note has been added to the SR Table to clarify that Table 3.3.6-1 determines which SRs apply to which Containment Purge System and Pressure Relief Line Isolation Functions.

SR 3.3.6.1

Performance of the CHANNEL CHECK once every 24 hours ensures that a gross failure of instrumentation has not occurred, and a CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION. A CHANNEL CHECK for a single channel instrument is satisfied by verification that the sensor or the signal processing equipment has not drifted outside its limits.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.6.1 (continued)

Agreement criteria are determined by the unit staff, based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the sensor or the signal processing equipment has drifted outside its limit.

The Frequency is based on operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the LCO required channels.

SR 3.3.6.2

SR 3.3.6.2 is the performance of an ACTUATION LOGIC TEST. This test is performed every 31 days on a STAGGERED TEST BASIS. The Surveillance interval is acceptable based on instrument reliability and industry operating experience.

SR 3.3.6.3

A COT is performed every 92 days on each radiation monitoring channel to ensure the entire channel will perform the intended Function. This test verifies the capability of the instrumentation to provide the containment purge system and pressure relief line isolation. The setpoint shall be left consistent with the current unit specific calibration procedure tolerance.

SR 3.3.6.4

SR 3.3.6.4 is the performance of a TADOT. This test is a check every 24 months that includes actuation of the end device (i.e., valve cycles, etc.).

The test also includes trip devices that provide actuation signals directly to the actuation instrumentation, bypassing the analog process control equipment. The SR is modified by a Note

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.6.4 (continued)

that excludes verification of setpoints during the TADOT. The Functions tested have no setpoints associated with them.

The Frequency is based on the known reliability of the Function and the redundancy available, and has been shown to be acceptable through operating experience.

SR 3.3.6.5

A CHANNEL CALIBRATION is performed every 24 months, or approximately at every refueling. CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to a measured parameter within the necessary range and accuracy. Allowable values and setpoints for these Functions are specified in the IP3 Offsite Dose Calculation Manual (Ref. 3).

The Frequency is based on operating experience and is consistent with the typical industry refueling cycle.

REFERENCES

1. FSAR Chapter 14.
2. Safety Evaluation Report (SER) for IP3 Amendment 175.
3. IP3 Offsite Dose Calculation Manual.

B 3.3 INSTRUMENTATION

B 3.3.7 Control Room Ventilation System (CRVS) Actuation Instrumentation

BASES

BACKGROUND

The CRVS provides an enclosed control room environment from which the unit can be operated following an uncontrolled release of radioactivity. During normal operation, the CRVS provides control room ventilation. Upon receipt of an actuation signal, the CRVS initiates filtered ventilation and pressurization of the control room. This system is described in the Bases for LCO 3.7.11 (Ventilation), "Control Room Ventilation System."

The control room operator can place the CRVS in the 10% incident mode described in the Bases for LCO 3.7.11, by manual mode selector switch in the control room. The CRVS is also actuated by a safety injection (SI) signal. The SI Function is discussed in LCO 3.3.2, "Engineered Safety Feature Actuation System (ESFAS) Instrumentation."

On a Safety Injection signal or high radiation in the Control Room (Radiation Monitor R-1), the CRVS will actuate to the <u>incident mode with outside air makeup</u> (i.e. 10% incident mode). This will cause one of the two filters booster fans to start, the locker room exhaust fan to stop, and CRVS dampers to open or close as necessary to filter incoming outside air and direct approximately 10% of the recirculated air through the filter unit. In the event that the first booster fan fails to start, the second booster fan will start after a predetermined time delay.

If for any reason it is required or desired to operate with 100% recirculated air (e.g., toxic gas condition is identified), the CRVS can be placed in the <u>incident mode with no outside air makeup</u> (i.e. 100% incident mode) by remote manually operated switches. The Firestat detector will also initiate 100% incident mode in the CRVS.

BASES

APPLICABLE SAFETY ANALYSES

The control room must be kept habitable for the operators stationed there during accident recovery and post accident operations.

The CRVS acts to limit the supply of unfiltered outside air to the control room, initiate filtration, and pressurize the control room. These actions are necessary to ensure the control room is kept habitable for the operators stationed there during accident recovery and post accident operations by minimizing the radiation exposure of control room personnel.

In MODES 1, 2, 3, and 4, SI signal actuation ensures initiation of the CRVS during a loss of coolant accident or steam generator tube rupture.

Radiation monitor R-1 is not required for the Operability of the Control Room Ventilation System because control room isolation is initiated by the safety injection signal in MODES 1, 2, 3 and 4 and control room isolation is not required for maintaining radiation exposure within General Design Criteria 19 limits following a fuel handling accident or gas-decay-tank rupture.

The CRVS does not actuate automatically in response to toxic gases. Separate chlorine, ammonia and oxygen probes are provided to detect the presence of these gases in the outside air intake. Additionally, monitors in the Control Room will detect low oxygen levels and high levels of chlorine and ammonia. The CRVS may be placed in the <u>incident mode with no outside air makeup</u> (i.e. 100% incident mode) to respond to these conditions. Instrumentation for toxic gas monitoring is governed by the IP3 Technical Requirements Manual (TRM) (Ref. 1).

Note that the original CRVS design was not required to meet single failure criteria and, although upgraded from the original design, CRVS does not satisfy all requirements in IEEE-279 for single failure tolerance.

The CRVS actuation instrumentation satisfies Criterion 3 of 10 CFR 50.36.

BASES

LCO

The LCO requirements ensure that instrumentation necessary to actuate the CRVS to the 10% incident mode is OPERABLE.

1. Manual Initiation

The LCO requires two channels OPERABLE because the CRVS mode selector switch has two channels (i.e., one channel for each train). The operator can initiate the CRVS at any time by using the CRVS mode selector switch in the control room. This action will cause actuation of all components in the same manner as the automatic actuation signal.

Each channel includes the common CRVS mode selector switch and the interconnecting wiring to the actuation logic cabinet.

2. Automatic Actuation Logic and Actuation Relays

The LCO requires two trains of Actuation Logic and Relays OPERABLE to ensure that no single random failure can prevent automatic actuation resulting from an SI signal.

Automatic Actuation Logic and Actuation relays are required to be OPERABLE to support the Operability of the function that starts CRVS (i.e., and ESFAS SI initiation signals). The term automatic actuation logic and actuation relays applies to those portions of the circuit that are: 1) common to more than one channel in one train of a single function (i.e., the automatic actuation logic); or, 2) the initiating relay contacts in one train responsible for actuating the equipment and which are common to more than one channel of a single function and more than one function (i.e., the actuation relays). There are two trains of automatic actuation logic and actuation relays for the containment purge system and pressure relief line.

If the SI functions becomes inoperable in such a manner that only the CRVS function is affected, the Conditions applicable to their SI function need not be entered. The less restrictive Actions specified for inoperability of the CRVS Functions specify sufficient compensatory measures for this case.

BASES

LCO (continued)

3. Safety Injection

Refer to LCO 3.3.2, Function 1, for all initiating Functions and requirements.

APPLICABILITY

The CRVS Functions must be OPERABLE in MODES 1, 2, 3 and 4 to ensure a habitable environment for the control room operators.

ACTIONS

A Note has been added to the ACTIONS indicating that separate Condition entry is allowed for each Function. The Conditions of this Specification may be entered independently for each Function listed in Table 3.3.7-1 in the accompanying LCO. The Completion Time(s) of the inoperable channel(s)/train(s) of a Function will be tracked separately for each Function starting from the time the Condition was entered for that Function.

A.1

Condition A applies to the manual channels and the actuation logic train Function of the CRVS.

If one channel or train is inoperable in one or more Functions, 7 days are permitted to restore it to OPERABLE status. The 7 day Completion Time is the same as is allowed if one train of the mechanical portion of the system is inoperable. The basis for this Completion Time is the same as provided in LCO 3.7.11. If the channel/train cannot be restored to OPERABLE status, CRVS must be placed in the emergency radiation protection mode of operation (i.e., the 10% incident mode). This starts both trains of CRVS because a single switch controls both trains. This accomplishes the actuation instrumentation Function and places the unit in a conservative mode of operation.

BASES

ACTIONS (continued)

B.1

Condition B applies to the failure of two CRVS actuation trains, or two manual channels. The first Required Action is to place CRVS in the 10% incident mode of operation within 72 hours. This starts both trains of CRVS because a single switch controls both trains. This accomplishes the actuation instrumentation Function that may have been lost and places the unit in a conservative mode of operation. This ensures appropriate limits are placed upon train inoperability as discussed in the Bases for LCO 3.7.11.

C.1 and C.2

Condition C applies when the Required Action and associated Completion Time for Condition A or B have not been met and the unit is in MODE 1, 2, 3, or 4. The unit must be brought to a MODE in which the LCO requirements are not applicable. To achieve this status, the unit must be brought to MODE 3 within 6 hours and MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

A Note has been added to the SR Table to clarify that Table 3.3.7-1 determines which SRs apply to which CRVS Actuation Functions.

SR 3.3.7.1

A COT is performed once every 92 days on each required channel to ensure the entire channel will perform the intended function. This test verifies the capability of the instrumentation to provide the CRVS actuation. The Frequency is based on the known

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.7.1 (continued)

reliability of the system and has been shown to be acceptable through operating experience.

SR 3.3.7.2

SR 3.3.7.2 is the performance of a TADOT. This test is a check of the Manual Actuation Functions and is performed every 24 months. Each Manual Actuation Function is tested up to, and including, the end device (i.e., fan starts, damper cycles, etc.).

The Frequency is based on the known reliability of the Function and has been shown to be acceptable through operating experience. The SR is modified by a Note that excludes verification of setpoints during the TADOT. The Functions tested have no setpoints associated with them.

REFERENCES

1. IP3 Technical Requirements Manual.

B 3.3 INSTRUMENTATION

B 3.3.8 Fuel Storage Building Emergency Ventilation System (FSBEVS) Actuation Instrumentation

BASES

BACKGROUND

The FSBEVS ensures that radioactive materials in the fuel building atmosphere following a fuel handling accident are filtered and adsorbed prior to exhausting to the environment. The system is described in the Bases for LCO 3.7.13, Fuel Storage Building Emergency Ventilation System (FSBEVS). The system initiates filtered ventilation of the fuel building automatically following receipt of a high radiation signal from fuel storage building area radiation monitor, R-5.

High radiation levels detected by the fuel storage building area radiation monitor, R-5, initiates fuel storage building isolation and starts the FSBEVS. These actions function to prevent exfiltration of contaminated air by initiating filtered ventilation, which imposes a negative pressure on the fuel storage building. Following an Area Radiation Monitor (R-5) signal or manual actuation to the emergency mode of operation, the FSBEVS ventilation supply fans stop automatically and the associated ventilation supply dampers close automatically. The charcoal filter face dampers (inlet and outlet dampers) open automatically, if not already open. Additionally, the rolling door closes, if open, and the inflatable seals on the man doors and truck door are actuated. The FSB exhaust fan continues to operate.

APPLICABLE SAFETY ANALYSES

The FSBEVS ensures that radioactive materials in the fuel building atmosphere following a fuel handling accident are filtered and adsorbed prior to being exhausted to the environment when the FSBEVS is aligned and operates as described in the Bases for LCO 3.7.13, Fuel Storage Building Emergency Ventilation System (FSBEVS). This action reduces the radioactive content in the fuel building exhaust following a LOCA or fuel handling

BASES

APPLICABLE SAFETY ANALYSES (continued)

accident so that offsite doses remain within the limits specified in 10 CFR 100 (Ref. 1).

The FSBEVS actuation instrumentation satisfies Criterion 3 of 10 CFR 50.36.

LCO

The LCO requirements ensure that instrumentation necessary for manual and automatic actuation of the FSBEVS is OPERABLE.

Manual and automatic FSBEVS initiation capability is OPERABLE when the Fuel Storage Building Area Radiation Monitor (R-5) signal or manual actuation to the emergency mode of operation will cause the realignment of the FSBEVS to the accident mode of operation as described in the Bases for LCO 3.7.13, Fuel Storage Building Emergency Ventilation System (FSBEVS).

The setpoint for Fuel Storage Building Area Radiation Monitor (R-5) is established in accordance with the Offsite Dose Calculation Manual (ODCM) (Ref. 2).

APPLICABILITY

The manual FSBEVS initiation must be OPERABLE when moving irradiated fuel assemblies in the fuel storage building, to ensure the FSBEVS operates to remove fission products associated with leakage after a fuel handling accident.

High radiation initiation of the FSBEVS must be OPERABLE in any MODE during movement of irradiated fuel assemblies in the fuel storage building to ensure automatic initiation of the FSBEVS when the potential for a fuel handling accident exists.

ACTIONS

The most common cause of channel inoperability is outright failure or drift of the bistable or process module sufficient to exceed the tolerance allowed by Reference 2. Typically, the drift is found to be small and results in a delay of actuation

BASES

ACTIONS (continued)

rather than a total loss of function. This determination is generally made during the performance of a COT, when the instrumentation is set up for adjustment to bring it within specification. If the Trip Setpoint is less conservative than the tolerance specified by Reference 2, the channel must be declared inoperable immediately and the appropriate Condition entered.

A.1 and A.2

This condition applies when the manual or automatic FSBEVS initiation capability is inoperable. The Required Action is to immediately place the system in operation as described in the Bases for LCO 3.7.13, FSBEVS. This accomplishes the actuation instrumentation function that may have been lost and places the unit in a accident mode of operation. Alternatively, movement of irradiated fuel assemblies in the fuel building must be suspended immediately to eliminate the potential for events that could require FSBEVS actuation. The Completion Time of immediately requires that the Required Action be pursued without delay and in a controlled manner.

SURVEILLANCE REQUIREMENTS

SR 3.3.8.1

Performance of the CHANNEL CHECK once every 24 hours ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

A CHANNEL CHECK for a single channel instrument is satisfied by verification that the sensor or the signal processing equipment has not drifted outside its limit.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.8.1 (continued)

The Frequency is based on operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal checks of a channel during normal operational use of the displays associated with the LCO required channel.

SR 3.3.8.2

A COT is performed for both the manual and automatic function once every 92 days to ensure the entire channel will perform the intended function. This test verifies the capability of the instrumentation to provide the FSBEVS actuation. The setpoints shall be left consistent with requirements of Reference 2. The Frequency of 92 days is based on the known reliability of the monitoring equipment and has been shown to be acceptable through operating experience. This test is typically performed in conjunction with SR 3.7.13.4 which verifies OPERABILITY of the activated devices.

SR 3.3.8.3

A CHANNEL CALIBRATION is performed every 24 months, or approximately at every refueling. CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies that the channel responds to a measured parameter within the necessary range and accuracy. The Frequency is based on operating experience and is consistent with the refueling cycle.

REFERENCES

1. 10 CFR 100.11.

2. IP3 Offsite Dose Calculation Manual.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.1 RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits

BASES

BACKGROUND

These Bases address requirements for maintaining RCS pressure, temperature, and flow rate within limits assumed in the safety analyses. The safety analyses (Ref. 1) of normal operating conditions and anticipated operational occurrences assume initial conditions within the normal steady state envelope. The limits placed on RCS pressure, temperature, and flow rate ensure that the minimum departure from nucleate boiling ratio (DNBR) will be met for each of the transients analyzed.

The RCS pressure limit is consistent with operation within the nominal operational envelope. Pressurizer pressure indications are averaged to come up with a value for comparison to the limit. A lower pressure will cause the reactor core to approach DNB limits.

The RCS coolant average loop temperature limit is consistent with full power operation within the nominal operational envelope. RCS average temperature is determined by calculating the average temperature for each loop and then calculating the average of these average loop temperatures and this average of the averages is compared to the acceptance criteria. A higher average temperature will cause the core to approach DNB limits.

The RCS flow rate normally remains constant during an operational fuel cycle with all pumps running. The minimum RCS flow limit corresponds to that assumed for DNB analyses. RCS flow rate is determined by calculating the average flow rate for each loop and then calculating the sum of these average loop flow rates and this sum of the averages is compared to the acceptance criteria. A lower RCS flow will cause the core to approach DNB limits.

Operation for significant periods of time outside these DNB limits increases the likelihood of a fuel cladding failure in a DNB limited event.

BASES

BACKGROUND (Continued)

Calculations have shown that reactor heat equivalent to 10% rated power can be removed via the steam generators with natural circulation without violating DNBR limits. This analysis assumed conservative flow resistances including steam generator tube plugging and a locked rotor in each loop (Ref. 1).

APPLICABLE SAFETY ANALYSES

The requirements of this LCO represent the initial conditions for DNB limited transients analyzed in the plant safety analyses (Ref. 1). The safety analyses have shown that transients initiated from the limits of this LCO will result in meeting the DNBR acceptance limit for the RCS DNB parameters. Changes to the unit that could impact these parameters must be assessed for their impact on the DNBR criteria. The transients analyzed include loss of coolant flow events and dropped or stuck rod events. A key assumption for the analysis of these events is that the core power distribution is within the limits of LCO 3.1.6, "Control Bank Insertion Limits"; LCO 3.2.3, "AXIAL FLUX DIFFERENCE (AFD)"; and LCO 3.2.4, "QUADRANT POWER TILT RATIO (QPTR)."

LCO

This LCO specifies limits on the monitored process variables (i.e., pressurizer pressure, RCS average loop temperature, and RCS total flow rate, to ensure the core operates within the limits assumed in the safety analyses. Operating within these limits will result in meeting the DNBR criterion in the event of a DNB limited transient.

The RCS total flow rate limit of 375,600 gpm allows a measurement uncertainty of 2.9% associated with the performance of Reactor coolant System Flow Calculation.

The pressurizer pressure limit of 2205 psig includes the allowance for measurement uncertainty and instrument error.

BASES

LCO (continued)

The limit on RCS average loop temperature provides assurance that RCS temperatures are maintained within the normal steady state envelope of operation assumed in the safety analyses performed to support the Vantage + fuel reloads with asymmetric tube plugging among steam generators. A maximum full power Tcold of 547.7°F (including control deadband and measurement uncertainties) was assumed in these safety analyses. A Tavg of 578.3°F assures that a Tcold of 547.7°F is not exceeded at a measured flow of ≥ 375,600 gpm when considering asymmetric tube plugging among steam generators for DNB considerations. Therefore, the LCO limit of 571.5°F for RCS average loop temperature, which is based on meeting analysis assumptions for post-LOCA containment integrity, conservatively ensures that DNBR limits are met.

The RCS DNB parameters satisfy Criterion 2 of 10 CFR 50.36.

APPLICABILITY

In MODE 1, the limits on pressurizer pressure, RCS coolant average temperature, and RCS flow rate must be maintained during steady state operation in order to ensure DNBR criteria will be met in the event of an unplanned loss of forced coolant flow or other DNB limited transient. In all other MODES, the power level is low enough that DNB is not a concern.

A Note has been added to indicate the limit on pressurizer pressure is not applicable during short term operational transients such as a THERMAL POWER ramp increase > 5% RTP per minute or a THERMAL POWER step increase > 10% RTP. These conditions represent short term perturbations where actions to control pressure variations might be counterproductive. Also, since they represent transients initiated from power levels < 100% RTP, an increased DNBR margin exists to offset the temporary pressure variations.

Another set of limits on DNB related parameters is provided in SL 2.1.1, "Reactor Core SLs." Those limits are less restrictive than the limits of this LCO, but violation of a Safety Limit (SL) merits a stricter, more severe Required Action. Should a

BASES

APPLICABILITY (continued)

violation of this LCO occur, the operator must check whether or not an SL may have been exceeded.

ACTIONS

A.1

RCS pressure and RCS average loop temperature are controllable and measurable parameters. With one or both of these parameters not within LCO limits, action must be taken to restore parameter(s).

RCS total flow rate is not a controllable parameter and is not expected to vary during steady state operation. If the indicated RCS total flow rate is below the LCO limit, power must be reduced, as required by Required Action B.1, to restore DNB margin and eliminate the potential for violation of the accident analysis bounds.

The 2 hour Completion Time for restoration of the parameters provides sufficient time to adjust plant parameters, to determine the cause for the off normal condition, and to restore the readings within limits, and is based on plant operating experience.

B.1

If Required Action A.1 is not met within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 2 within 6 hours. In MODE 2, the reduced power condition eliminates the potential for violation of the accident analysis bounds. The Completion Time of 6 hours is reasonable to reach the required plant conditions in an orderly manner.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.1.1

Since Required Action A.1 allows a Completion Time of 2 hours to restore parameters that are not within limits, the 12 hour Surveillance Frequency for pressurizer pressure is sufficient to ensure the pressure can be restored to a normal operation, steady state condition following load changes and other expected transient operations. Pressurizer pressure indications are averaged to determine the value for comparison to the LCO limit. The 12 hour interval has been shown by operating practice to be sufficient to regularly assess for potential degradation and to verify operation is within safety analysis assumptions.

SR 3.4.1.2

Since Required Action A.1 allows a Completion Time of 2 hours to restore parameters that are not within limits, the 12 hour Surveillance Frequency for RCS average loop temperature is sufficient to ensure the temperature can be restored to a normal operation, steady state condition following load changes and other expected transient operations. RCS average loop temperature is determined by calculating the average temperature for each loop and then calculating the average of these average loop temperatures and this average of the averages is compared to the acceptance criteria. The 12 hour interval has been shown by operating practice to be sufficient to regularly assess for potential degradation and to verify operation is within safety analysis assumptions.

SR 3.4.1.3

The 12 hour Surveillance Frequency for RCS total flow rate is performed using the installed flow instrumentation. The 12 hour interval has been shown by operating practice to be sufficient to regularly assess potential degradation and to verify operation within safety analysis assumptions.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.1.4

Measurement of RCS total flow rate by performance of a precision calorimetric heat balance once every 24 months verifies that the actual RCS flow rate is greater than or equal to the minimum required RCS flow rate.

The Frequency of 24 months reflects the importance of verifying flow after a refueling outage when the core has been altered, SG tubes plugged or other activities performed, which may have caused an alteration of flow resistance.

This SR is modified by a Note that allows entry into MODE 1, without having performed the SR, and placement of the unit in the best condition for performing the SR. The Note states that the SR is not required to be performed until 24 hours after ≥ 90% RTP. This exception is appropriate since the heat balance requires the plant to be at a minimum of 90% RTP to obtain the stated RCS flow accuracies. The Surveillance shall be performed within 24 hours after reaching 90% RTP.

REFERENCES

1. FSAR, Section 14.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.2 RCS Minimum Temperature for Criticality

BASES

BACKGROUND

This LCO is based upon meeting several major considerations before the reactor can be made critical and while the reactor is critical.

The first consideration is moderator temperature coefficient (MTC), LCO 3.1.3, "Moderator Temperature Coefficient (MTC)." In the transient and accident analyses, the MTC is assumed to be negative (except during physics testing) and the operating temperature is assumed to be within the nominal operating envelope while the reactor is critical. The LCO on minimum temperature for criticality helps ensure the plant is operated consistent with these assumptions.

The second consideration is the protective instrumentation. Because certain protective instrumentation (e.g., excore neutron detectors) can be affected by moderator temperature, a temperature value within the nominal operating envelope is chosen to ensure proper indication and response while the reactor is critical.

The third consideration is the pressurizer operating characteristics. The transient and accident analyses assume that the pressurizer is within its normal startup and operating range (i.e., saturated conditions and steam bubble present). It is also assumed that the RCS temperature is within its normal expected range for startup and power operation. Since the density of the water, and hence the response of the pressurizer to transients, depends upon the initial temperature of the moderator, a minimum value for moderator temperature within the nominal operating envelope is chosen.

The fourth consideration is that the reactor vessel is above its minimum nil ductility reference temperature when the reactor is critical.

BASES

APPLICABLE SAFETY ANALYSES

Although the RCS minimum temperature for criticality is not itself an initial condition assumed in Design Basis Accidents (DBAs), the closely aligned temperature for hot zero power (HZP) is a process variable that is an initial condition of DBAs, such as the rod cluster control assembly (RCCA) withdrawal, RCCA ejection, and main steam line break accidents performed at zero power that either assumes the failure of, or presents a challenge to, the integrity of a fission product barrier.

All low power safety analyses assume initial RCS loop temperatures ≥ the HZP temperature of 547°F (Ref. 1). The minimum temperature for criticality limitation provides a small band, 7°F, for critical operation below HZP. This band allows critical operation below HZP during plant startup and does not adversely affect any safety analyses since the MTC is not significantly affected by the small temperature difference between HZP and the minimum temperature for criticality.

The RCS minimum temperature for criticality satisfies Criterion 2 of 10 CFR 50.36.

LCO

Compliance with the LCO ensures that the reactor will not be made or maintained critical ($k_{eff} \geq 1.0$) at a temperature less than a small band below the HZP temperature, which is assumed in the safety analysis. Failure to meet the requirements of this LCO may produce initial conditions inconsistent with the initial conditions assumed in the safety analysis.

APPLICABILITY

In MODE 1 and MODE 2 with $k_{eff} \geq 1.0$, LCO 3.4.2 is applicable since the reactor can only be critical ($k_{eff} \geq 1.0$) in these MODES.

The special test exception of LCO 3.1.8, "MODE 2 PHYSICS TESTS Exceptions," permits PHYSICS TESTS to be performed at ≤ 5% RTP with RCS loop average temperatures slightly lower than normally allowed so that fundamental nuclear characteristics of the core

BASES

APPLICABILITY (continued)

can be verified. In order for nuclear characteristics to be accurately measured, it may be necessary to operate outside the normal restrictions of this LCO. For example, to measure the MTC at beginning of cycle, it is necessary to allow RCS loop average temperatures to fall below $T_{no\ load}$, which may cause RCS loop average temperatures to fall below the temperature limit of this LCO.

ACTIONS

A.1

If the parameters that are outside the limit cannot be restored, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 2 with $k_{eff} < 1.0$ within 30 minutes. Rapid reactor shutdown can be readily and practically achieved within a 30 minute period. The allowed time is reasonable, based on operating experience, to reach MODE 2 $k_{eff} < 1.0$ in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.2.1

RCS loop average temperature is required to be verified at or above 540°F every 30 minutes when T_{avg}-T_{ref} deviation, and low T_{avg} alarm is not reset and any RCS loop T_{avg} < 547°F.

The Note modifies the SR. When any RCS loop average temperature is < 547°F and the T_{avg} - T_{ref} deviation, and low T_{avg} alarm are alarming, RCS loop average temperatures could fall below the LCO requirement without additional warning. The SR to verify RCS loop average temperatures every 30 minutes is frequent enough to prevent the inadvertent violation of the LCO.

BASES

REFERENCES

1. FSAR, Section 14.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.3 RCS Pressure and Temperature (P/T) Limits

BASES

BACKGROUND

All components of the RCS are designed to withstand effects of cyclic loads due to system pressure and temperature changes. These loads are introduced by startup (heatup) and shutdown (cooldown) operations, power transients, and reactor trips. This LCO limits the pressure and temperature changes during RCS heatup and cooldown, within the design assumptions and the stress limits for cyclic operation.

The Pressure and Temperature Limits Report (PTLR) contains P/T limit curves for heatup, cooldown, inservice leak and hydrostatic (ISLH) testing, and data for the maximum rate of change of reactor coolant temperature (Ref. 1).

Each P/T limit curve defines an acceptable region for normal operation. The usual use of the curves is operational guidance during heatup or cooldown maneuvering, when pressure and temperature indications are monitored and compared to the applicable curve to determine that operation is within the allowable region.

The LCO establishes operating limits that provide a margin to brittle failure of the reactor vessel and piping of the reactor coolant pressure boundary (RCPB). The vessel is the component most subject to brittle failure, and the LCO limits apply mainly to the vessel. The limits do not apply to the pressurizer, which has different design characteristics and operating functions.

10 CFR 50, Appendix G (Ref. 2), requires the establishment of P/T limits for specific material fracture toughness requirements of the RCPB materials. Reference 2 requires an adequate margin to brittle failure during normal operation, anticipated operational occurrences, and system hydrostatic tests. It mandates the use of the American Society of Mechanical Engineers (ASME) Code, Section III, Appendix G (Ref. 3).

BASES

BACKGROUND (Continued)

The neutron embrittlement effect on the material toughness is reflected by increasing the nil ductility reference temperature (RT_{NDT}) as exposure to neutron fluence increases.

The actual shift in the RT_{NDT} of the vessel material will be established periodically by removing and evaluating the irradiated reactor vessel material specimens, in accordance with ASTM E 185 (Ref. 4) and Appendix H of 10 CFR 50 (Ref. 5). The operating P/T limit curves will be adjusted, as necessary, based on the evaluation findings and the recommendations of Regulatory Guide 1.99 (Ref. 6).

The P/T limit curves are composite curves established by superimposing limits derived from stress analyses of those portions of the reactor vessel and head that are the most restrictive. At any specific pressure, temperature, and temperature rate of change, one location within the reactor vessel will dictate the most restrictive limit. Across the span of the P/T limit curves, different locations are more restrictive, and, thus, the curves are composites of the most restrictive regions.

The heatup curve represents a different set of restrictions than the cooldown curve because the directions of the thermal gradients through the vessel wall are reversed. The thermal gradient reversal alters the location of the tensile stress between the outer and inner walls.

The criticality limit curve includes the Reference 2 requirement that it be ≥ 40°F above the heatup curve or the cooldown curve, and not less than the minimum permissible temperature for ISLH testing. However, the criticality curve is not operationally limiting; a more restrictive limit exists in LCO 3.4.2, "RCS Minimum Temperature for Criticality."

The consequence of violating the LCO limits is that the RCS has been operated under conditions that can result in brittle failure of the RCPB, possibly leading to a nonisolable leak or loss of coolant accident. In the event these limits are exceeded, an

BASES

BACKGROUND (continued)

evaluation must be performed to determine the effect on the structural integrity of the RCPB components. The ASME Code, Section XI, Appendix E (Ref. 7), provides a recommended methodology for evaluating an operating event that causes an excursion outside the limits.

APPLICABLE SAFETY ANALYSES

The P/T limits are not derived from Design Basis Accident (DBA) analyses. They are prescribed during normal operation to avoid encountering pressure, temperature, and temperature rate of change conditions that might cause undetected flaws to propagate and cause nonductile failure of the RCPB, an unanalyzed condition. Reference 1 establishes the methodology for determining the P/T limits. Although the P/T limits are not derived from any DBA, the P/T limits are acceptance limits since they preclude operation in an unanalyzed condition.

RCS P/T limits satisfy Criterion 2 of 10 CFR 50.36.

LCO

The two elements of this LCO are:

a. The limit curves for heatup, cooldown, and ISLH testing; and

b. Limits on the rate of change of temperature.

The LCO limits apply to all components of the RCS pressure boundary, except the pressurizer. These limits define allowable operating regions and permit a large number of operating cycles while providing a wide margin to nonductile failure.

The limits for the rate of change of temperature control the thermal gradient through the vessel wall and are used as inputs for calculating the heatup, cooldown, and ISLH testing P/T limit curves. Thus, the LCO for the rate of change of temperature restricts stresses caused by thermal gradients and also ensures

BASES

LCO (continued)

the validity of the P/T limit curves. Heatup and cooldown limits are specified in hourly increments (i.e., the heatup and cooldown limits are based on the temperature change averaged over a one hour period).

Violating the LCO limits places the reactor vessel outside of the bounds of the stress analyses and can increase stresses in other RCPB components. The consequences depend on several factors, as follows:

a. The severity of the departure from the allowable operating P/T regime or the severity of the rate of change of temperature;

b. The length of time the limits were violated (longer violations allow the temperature gradient in the thick vessel walls to become more pronounced); and

c. The existences, sizes, and orientations of flaws in the vessel material.

APPLICABILITY

The RCS P/T limits LCO provides a definition of acceptable operation for prevention of nonductile failure in accordance with 10 CFR 50, Appendix G (Ref. 2). Although the P/T limits were developed to provide guidance for operation during heatup or cooldown (MODES 3, 4, and 5) or ISLH testing, their Applicability is at all times in keeping with the concern for nonductile failure. The limits do not apply to the pressurizer.

During MODES 1 and 2, other Technical Specifications provide limits for operation that can be more restrictive than or can supplement these P/T limits. LCO 3.4.1, "RCS Pressure, Temperature, and Flow Departure from Nucleate Boiling (DNB) Limits"; LCO 3.4.2, "RCS Minimum Temperature for Criticality"; and Safety Limit 2.1, "Safety Limits," also provide operational restrictions for pressure and temperature and maximum pressure. Furthermore, MODES 1 and 2 are above the temperature range of concern for nonductile failure, and stress analyses have been

BASES

APPLICABILITY (continued)

performed for normal maneuvering profiles, such as power ascension or descent.

ACTIONS

A.1 and A.2

Operation outside the P/T limits during MODE 1, 2, 3, or 4 must be corrected so that the RCPB is returned to a condition that has been verified by stress analyses.

The 30 minute Completion Time reflects the urgency of restoring the parameters to within the analyzed range. Most violations will not be severe, and the activity can be accomplished in this time in a controlled manner.

Besides restoring operation within limits, an evaluation is required to determine if RCS operation can continue. The evaluation must verify the RCPB integrity remains acceptable and must be completed before continuing operation. Several methods may be used, including comparison with pre-analyzed transients in the stress analyses, new analyses, or inspection of the components.

ASME Code, Section XI, Appendix E (Ref. 7), may be used to support the evaluation. However, its use is restricted to evaluation of the vessel beltline.

The 72 hour Completion Time is reasonable to accomplish the evaluation. The evaluation for a mild violation is possible within this time, but more severe violations may require special, event specific stress analyses or inspections. A favorable evaluation must be completed before continuing to operate.

Condition A is modified by a Note requiring Required Action A.2 to be completed whenever the Condition is entered. The Note emphasizes the need to perform the evaluation of the effects of the excursion outside the allowable limits. Restoration alone per Required Action A.1 is insufficient because higher than analyzed stresses may have occurred and may have affected the RCPB integrity.

BASES

ACTIONS

B.1 and B.2

If a Required Action and associated Completion Time of Condition A are not met, the plant must be placed in a lower MODE because either the RCS remained in an unacceptable P/T region for an extended period of increased stress or a sufficiently severe event caused entry into an unacceptable region. Either possibility indicates a need for more careful examination of the event, best accomplished with the RCS at reduced pressure and temperature. In reduced pressure and temperature conditions, the possibility of propagation with undetected flaws is decreased.

If the required restoration activity cannot be accomplished within 30 minutes, Required Action B.1 and Required Action B.2 must be implemented to reduce pressure and temperature.

If the required evaluation for continued operation cannot be accomplished within 72 hours or the results are indeterminate or unfavorable, action must proceed to reduce pressure and temperature as specified in Required Action B.1 and Required Action B.2. A favorable evaluation must be completed and documented before returning to operating pressure and temperature conditions.

Pressure and temperature are reduced by bringing the plant to MODE 3 within 6 hours and to MODE 5 with RCS pressure significantly reduced and limited by LCO 3.4.12, Low Temperature Overpressure Protection (LTOP), within 36 hours.

The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

C.1 and C.2

Actions must be initiated immediately to correct operation outside of the P/T limits at times other than when in MODE 1, 2, 3, or 4, so that the RCPB is returned to a condition that has been verified by stress analysis.

BASES

ACTIONS

C.1 and C.2 (continued)

The immediate Completion Time reflects the urgency of initiating action to restore the parameters to within the analyzed range. Most violations will not be severe, and the activity can be accomplished in this time in a controlled manner.

Besides restoring operation within limits, an evaluation is required to determine if RCS operation can continue. The evaluation must verify that the RCPB integrity remains acceptable and must be completed prior to entry into MODE 4. Several methods may be used, including comparison with pre-analyzed transients in the stress analyses, or inspection of the components.

ASME Code, Section XI, Appendix E (Ref. 7), may be used to support the evaluation. However, its use is restricted to evaluation of the vessel beltline.

Condition C is modified by a Note requiring Required Action C.2 to be completed whenever the Condition is entered. The Note emphasizes the need to perform the evaluation of the effects of the excursion outside the allowable limits. Restoration alone per Required Action C.1 is insufficient because higher than analyzed stresses may have occurred and may have affected the RCPB integrity.

SURVEILLANCE REQUIREMENTS

SR 3.4.3.1

Verification that operation is within the PTLR limits is required every 30 minutes when RCS pressure and temperature conditions are undergoing planned changes. This Frequency is considered reasonable in view of the control room indication available to monitor RCS status. Heatup and cooldown limits are specified in hourly increments (i.e., the heatup and cooldown limits are based on the temperature change averaged over a one hour period). Also,

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.3.1 (continued)

since temperature rate of change limits are specified in hourly increments, 30 minutes permits assessment and correction for minor deviations within a reasonable time.

Surveillance for heatup, cooldown, or ISLH testing may be discontinued when the definition given in the relevant plant procedure for ending the activity is satisfied.

This SR is modified by a Note that only requires this SR to be performed during system heatup, cooldown, and ISLH testing. No SR is given for criticality operations because LCO 3.4.2 contains a more restrictive requirement.

REFERENCES

1. WCAP-7924-A, July 1972.
2. 10 CFR 50, Appendix G.
3. ASME, Boiler and Pressure Vessel Code, Section III, Appendix G.
4. ASTM E 185-70.
5. 10 CFR 50, Appendix H.
6. Regulatory Guide 1.99, Revision 2, May 1988.
7. ASME, Boiler and Pressure Vessel Code, Section XI, Appendix E.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.4 RCS Loops – MODES 1 and 2

BASES

BACKGROUND

The primary function of the RCS is removal of the heat generated in the fuel due to the fission process, and transfer of this heat, via the steam generators (SGs), to the secondary plant.

The secondary functions of the RCS include:

a. Moderating the neutron energy level to the thermal state, to increase the probability of fission;

b. Improving the neutron economy by acting as a reflector;

c. Carrying the soluble neutron poison, boric acid;

d. Providing a second barrier against fission product release to the environment; and

e. Removing the heat generated in the fuel due to fission product decay following a unit shutdown.

The reactor coolant is circulated through four loops connected in parallel to the reactor vessel, each containing an SG, a reactor coolant pump (RCP), and appropriate flow and temperature instrumentation for both control and protection. The reactor vessel contains the fuel. The SGs provide the heat sink to the isolated secondary coolant. The RCPs circulate the coolant through the reactor vessel and SGs at a sufficient rate to ensure proper heat transfer and prevent fuel damage. This forced circulation of the reactor coolant ensures mixing of the coolant for proper boration and chemistry control.

Calculations have shown that reactor heat equivalent to 10% rated power can be removed via the steam generators with natural circulation without violating DNBR limits. This analysis assumed conservative flow resistances including steam generator tube plugging and a lock rotor in each loop (Ref.1).

BASES

APPLICABLE SAFETY ANALYSES

Safety analyses contain various assumptions for the design bases accident initial conditions including RCS pressure, RCS temperature, reactor power level, core parameters, and safety system setpoints. The important aspect for this LCO is the reactor coolant forced flow rate, which is represented by the number of RCS loops in service.

Both transient and steady state analyses have been performed to establish the effect of flow on the departure from nucleate boiling (DNB). The transient and accident analyses for the plant have been performed assuming four RCS loops are in operation. The majority of the plant safety analyses are based on initial conditions at high core power or zero power. The accident analyses that are most important to RCP operation are the four pump coastdown, single pump locked rotor, single pump (broken shaft or coastdown), and rod withdrawal events (Ref. 1).

Steady state DNB analysis has been performed for the four RCS loop operation. For four RCS loop operation, the steady state DNB analysis, which generates the pressure and temperature Safety Limit (SL) (i.e., the departure from nucleate boiling ratio (DNBR) limit) assumes a maximum power level of 109% RTP. This is the design overpower condition for four RCS loop operation. The value for the accident analysis stet of the nuclear overpower (high flux) trip is 108% and is based on an analysis assumption that bounds possible instrumentation errors. The DNBR limit defines a locus of pressure and temperature points that result in a minimum DNBR greater than or equal to the critical heat flux correlation limit.

The plant is designed to operate with all RCS loops in operation to maintain DNBR above the SL, during all normal operations and anticipated transients. By ensuring heat transfer in the nucleate boiling region, adequate heat transfer is provided between the fuel cladding and the reactor coolant.

RCS Loops – MODES 1 and 2 satisfy Criterion 2 of 10 CFR 50.36.

BASES

LCO

The purpose of this LCO is to require an adequate forced flow rate for core heat removal. Flow is represented by the number of RCPs in operation for removal of heat by the SGs. To meet safety analysis acceptance criteria for DNB, four pumps are required at rated power.

An OPERABLE RCS loop consists of an OPERABLE RCP in operation providing forced flow for heat transport and an OPERABLE SG in accordance with the Steam Generator Surveillance Program.

APPLICABILITY

In MODES 1 and 2, the reactor is critical and thus has the potential to produce maximum THERMAL POWER. Thus, to ensure that the assumptions of the accident analyses remain valid, all RCS loops are required to be OPERABLE and in operation in these MODES to prevent DNB and core damage.

The decay heat production rate is much lower than the full power heat rate. As such, the forced circulation flow and heat sink requirements are reduced for lower, noncritical MODES as indicated by the LCOs for MODES 3, 4, and 5.

Operation in other MODES is covered by:

LCO 3.4.5, "RCS Loops – MODE 3";
LCO 3.4.6, "RCS Loops – MODE 4";
LCO 3.4.7, "RCS Loops – MODE 5, Loops Filled";
LCO 3.4.8, "RCS Loops – MODE 5, Loops Not Filled";
LCO 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation – High Water Level" (MODE 6); and
LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation – Low Water Level" (MODE 6).

ACTIONS

A.1

If the requirements of the LCO are not met, the Required Action is to reduce power and bring the plant to MODE 3. This lowers power level and thus reduces the core heat removal needs and minimizes the possibility of violating DNB limits.

BASES

ACTIONS

A.1 (continued)

The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging safety systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.4.1

This SR requires verification every 12 hours that each RCS loop is in operation. Verification can be based on flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing heat removal while maintaining the margin to DNB. The Frequency of 12 hours is sufficient considering other indications and alarms available to the operator in the control room to monitor RCS loop performance.

REFERENCES

1. FSAR, Section 14.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.5 RCS Loops – MODE 3

BASES

BACKGROUND

In MODE 3, the primary function of the reactor coolant is removal of decay heat and transfer of this heat, via the steam generator (SG), to the secondary plant fluid. The secondary function of the reactor coolant is to act as a carrier for soluble neutron poison, boric acid.

The reactor coolant is circulated through four RCS loops, connected in parallel to the reactor vessel, each containing an SG, and a reactor coolant pump (RCP). Appropriate flow, pressure, and temperature instrumentation are available for control, protection, and indication. The reactor vessel contains the fuel. The SGs provide the heat sink. The RCPs circulate the water through the reactor vessel and SGs at a sufficient rate to ensure proper heat transfer and prevent fuel damage.

In MODE 3, RCPs are used to provide forced circulation for heat removal during heatup and cooldown. The MODE 3 decay heat removal requirements are low enough that a single RCS loop with one RCP running is sufficient to remove core decay heat. However, two RCS loops are required to be OPERABLE to ensure redundant capability for decay heat removal.

Calculations have shown that reactor decay heat equivalent to 10% rated power can be removed via the steam generators with natural circulation. This analysis assumed conservative flow resistences including steam generator tube plugging and a lock rotor in each loop (Ref. 1).

APPLICABLE SAFETY ANALYSES

Whenever the reactor trip breakers (RTBs) are in the closed position and the control rod drive mechanisms (CRDMs) are energized, an inadvertent rod withdrawal from subcritical, resulting in a power excursion, is possible. Such a transient could be caused by a malfunction of the rod control system. In addition, the possibility of a power excursion due to the

BASES

APPLICABLE SAFETY ANALYSES (continued)

ejection of an inserted control rod is possible with the breakers closed or open. Such a transient could be caused by the mechanical failure of a CRDM.

Therefore, in MODE 3 with RTBs in the closed position and Rod Control System capable of rod withdrawal, uncontrolled control rod withdrawal from subcritical is postulated and requires at least two RCS loops to be OPERABLE and in operation to ensure that the accident analyses limits are met. For those conditions when the Rod Control System is not capable of rod withdrawal, two RCS loops are required to be OPERABLE, but only one RCS loop is required to be in operation to be consistent with MODE 3 accident analyses.

Failure to provide decay heat removal may result in challenges to a fission product barrier. The RCS loops are part of the primary success path that functions or actuates to prevent or mitigate a Design Basis Accident or transient that either assumes the failure of, or presents a challenge to, the integrity of a fission product barrier.

RCS Loops – MODE 3 satisfy Criterion 3 of 10 CFR 50.36.

LCO

The purpose of this LCO is to require that at least two RCS loops be OPERABLE. In MODE 3 with the RTBs in the closed position and Rod Control System capable of rod withdrawal, two RCS loops must be in operation. Two RCS loops are required to be in operation in MODE 3 with RTBs closed and Rod Control System capable of rod withdrawal due to the postulation of a power excursion because of an uncontrolled rod withdrawal. The required number of RCS loops in operation ensures that the Safety Limit criteria will be met for all of the postulated accidents.

With the RTBs in the open position, or the CRDMs de-energized, the Rod Control System is not capable of rod withdrawal; therefore, only one RCS loop in operation is necessary to ensure removal of decay heat from the core and homogenous boron concentration throughout the RCS. An additional RCS loop is

BASES

LCO (continued)

required to be OPERABLE to ensure redundant decay heat removal capability.

The Note permits all RCPs to be not be in operation for ≤ 1 hour per 8 hour period. The purpose of the Note is to permit performance of required tests or maintenance that can only be performed with all reactor coolant pumps not in operation. The 1 hour time period specified is acceptable because operating experience has shown that boron stratification is not a problem during this short period with no forced flow.

Utilization of the Note is permitted provided the following conditions are met, along with any other conditions imposed by test or maintenance procedures:

a. No operations are permitted that would dilute the RCS boron concentration, thereby maintaining the margin to criticality. Boron reduction is prohibited because a uniform concentration distribution throughout the RCS cannot be ensured when in natural circulation; and

b. Core outlet temperature is maintained at least 10°F below saturation temperature, so that no vapor bubble may form and possibly cause a natural circulation flow obstruction.

An OPERABLE RCS loop consists of one OPERABLE RCP and one OPERABLE SG in accordance with the Steam Generator Tube Surveillance Program, which has the minimum water level specified in SR 3.4.5.2. An RCP is OPERABLE if it is capable of being powered and is able to provide forced flow if required.

APPLICABILITY

In MODE 3, this LCO ensures forced circulation of the reactor coolant to remove decay heat from the core and to provide proper boron mixing. The most stringent condition of the LCO, that is, two RCS loops OPERABLE and two RCS loops in operation, applies to MODE 3 with RTBs in the closed position. The least stringent

BASES

APPLICABILITY (continued)

condition, that is, two RCS loops OPERABLE and one RCS loop in operation, applies to MODE 3 with the RTBs open.

Operation in other MODES is covered by:

LCO 3.4.4, "RCS Loops – MODES 1 and 2";
LCO 3.4.6, "RCS Loops – MODE 4";
LCO 3.4.7, "RCS Loops – MODE 5, Loops Filled";
LCO 3.4.8, "RCS Loops – MODE 5, Loops Not Filled";
LCO 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation – High Water Level" (MODE 6); and
LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation – Low Water Level" (MODE 6).

ACTIONS

A.1

If one required RCS loop is inoperable, redundancy for forced circulation heat removal is lost. The Required Action is restoration of the required RCS loop to OPERABLE status within the Completion Time of 72 hours. This time allowance is a justified period to be without the redundant, nonoperating loop because a single loop in operation has a heat transfer capability greater than that needed to remove the decay heat produced in the reactor core and because of the low probability of a failure in the remaining loop occurring during this period.

B.1

If restoration is not possible within 72 hours, the unit must be brought to MODE 4. In MODE 4, the unit may be placed on the Residual Heat Removal System. The additional Completion Time of 12 hours is compatible with required operations to achieve cooldown and depressurization from the existing plant conditions in an orderly manner and without challenging plant systems.

BASES

ACTIONS (continued)

C.1 and C.2

If the required RCS loop is not in operation, and the RTBs are closed and Rod Control System is capable of rod withdrawal, the Required Action is either to restore the required RCS loop to operation or to de-energize all CRDMs by opening the RTBs or de-energizing the motor generator (MG) sets. When the RTBs are in the closed position and Rod Control System are capable of rod withdrawal, it is postulated that a power excursion could occur in the event of an inadvertent control rod withdrawal. This mandates having the heat transfer capacity of two RCS loops in operation. If only one loop is in operation, the RTBs must be opened. The Completion Times of 1 hour to restore the required RCS loop to operation or de-energize all CRDMs is adequate to perform these operations in an orderly manner without exposing the unit to risk for an undue time period.

D.1, D.2, and D.3

If two required RCS loops are inoperable or no RCS loop is in operation, except as during conditions permitted by the Note in the LCO section, all CRDMs must be de-energized by opening the RTBs or de-energizing the MG sets. All operations involving a reduction of RCS boron concentration must be suspended, and action to restore one of the RCS loops to OPERABLE status and operation must be initiated. Boron dilution requires forced circulation for proper mixing, and opening the RTBs or de-energizing the MG sets removes the possibility of an inadvertent rod withdrawal. The immediate Completion Time reflects the importance of maintaining operation for forced circulation heat removal. The action to restore must be continued until one loop is restored to OPERABLE status and operation.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.5.1

This SR requires verification every 12 hours that the required loops are in operation. Verification can be based on flow rate, temperature, or pump status monitoring, which ensure that forced flow is providing heat removal. The Frequency of 12 hours is sufficient considering other indications and alarms available to the operator in the control room to monitor RCS loop performance.

SR 3.4.5.2

SR 3.4.5.2 requires verification of SG OPERABILITY. SG OPERABILITY is verified by ensuring that the actual secondary side water level is ≥ 71% (wide range equivalent) for each required loop. Depending on plant conditions, either wide range or narrow range SG level instruments may be used to verify this SR is met. Operators may be required to adjust the indicated level to compensate for the effects of SG temperature. If the SG secondary side actual water level is < 71%, the tubes may become uncovered and the associated loop may not be capable of providing the heat sink for removal of the decay heat. The 12 hour Frequency is considered adequate in view of other indications available in the control room to alert the operator to a loss of SG level.

SR 3.4.5.3

Verification that the required RCPs are OPERABLE ensures that an additional RCP can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power availability to the required RCPs.

REFERENCES None.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.6 RCS Loops – MODE 4

BASES

BACKGROUND

In MODE 4, the primary function of the reactor coolant is the removal of decay heat and the transfer of this heat to either the steam generator (SG) secondary side coolant or the component cooling water via the residual heat removal (RHR) heat exchangers. The secondary function of the reactor coolant is to act as a carrier for soluble neutron poison, boric acid.

The reactor coolant is circulated through four RCS loops connected in parallel to the reactor vessel, each loop containing a SG and a reactor coolant pump (RCP). Appropriate flow, pressure, and temperature instrumentation are available for control, protection, and indication. The RCPs and RHR pumps circulate the coolant through the reactor vessel and SGs at a sufficient rate to ensure proper heat transfer and to prevent boric acid stratification.

Each RHR loop consists of one RHR pump and one RHR heat exchanger as well as associated piping and valves to transfer heat between the RHR heat exchanger and the core. Although either RHR heat exchanger may be credited for either RHR loop, one RHR heat exchanger must be OPERABLE for each OPERABLE RHR loop.

In MODE 4, either RCPs or RHR loops can be used to provide forced circulation. The intent of this LCO is to provide forced flow from at least one RCP or one RHR loop for decay heat removal and transport. The flow provided by one RCP loop or RHR loop is adequate for decay heat removal. The other intent of this LCO is to require that two paths be available to provide redundancy for decay heat removal.

When the boron concentration of the RCS is reduced, the process should be uniform to prevent sudden reactivity changes. Mixing of the reactor coolant will be sufficient to maintain a uniform boron concentration if at least one reactor coolant pump or one residual heat removal pump is running while boron concentration is being changed. The residual heat removal pump will circulate the primary system volume in approximately one half hour. Boron

BASES

BACKGROUND (Continued)

concentration in the pressurizer is not a concern because of the low pressurizer volume and because the pressurizer boron concentration will be higher than that of the rest of the reactor coolant.

Calculations have shown that reactor decay heat equivalent to 10% rated power can be removed via the steam generators with natural circulation. This analysis assumed conservative flow resistances including steam generator tube plugging and a lock rotor in each loop (Ref. 1).

APPLICABLE SAFETY ANALYSES

In MODE 4, RCS circulation is considered in the determination of the time available for mitigation of the accidental boron dilution event. The RCS and RHR loops provide this circulation.

RCS Loops – MODE 4 satisfy Criterion 4 of 10 CFR 50.36.

LCO

The purpose of this LCO is to require that at least two loops be OPERABLE in MODE 4 and that one of these loops be in operation. The LCO allows the two loops that are required to be OPERABLE to consist of any combination of RCS loops and RHR loops. Any one loop in operation provides enough flow to remove the decay heat from the core with forced circulation. An additional loop is required to be OPERABLE to provide redundancy for heat removal.

Note 1 permits all RCPs and RHR pumps to not be in operation for $\leq$ 1 hour per 8 hour period. The purpose of the Note is to permit performance of required tests or maintenance that can only be performed with no forced circulation. The 1 hour time period is acceptable because operating experience has shown that boron stratification is not a problem during this short period with no forced flow.

BASES

LCO (continued)

Utilization of Note 1 is permitted provided the following conditions are met along with any other conditions imposed by test or maintenance procedures:

a. No operations are permitted that would dilute the RCS boron concentration, therefore maintaining the margin to criticality. Boron reduction is prohibited because a uniform concentration distribution throughout the RCS cannot be ensured when in natural circulation; and

b. Core outlet temperature is maintained at least 10°F below saturation temperature, so that no vapor bubble may form and possibly cause a natural circulation flow obstruction.

Note 2 requires that the reactor coolant pump starting requirments of LCO 3.4.12, Low Temperature Overpressure Protection (LTOP), must be met before the start of an RCP with any RCS cold leg temperature less than or equal to the LTOP arming temperature. This restraint is to prevent a low temperature overpressure event due to a thermal transient when an RCP is started.

An OPERABLE RCS loop comprises an OPERABLE RCP and an OPERABLE SG in accordance with the Steam Generator Tube Surveillance Program, which has the minimum water level specified in SR 3.4.6.2.

Similarly for the RHR System, an OPERABLE RHR loop comprises an OPERABLE RHR pump capable of providing forced flow to an OPERABLE RHR heat exchanger. RCPs and RHR pumps are OPERABLE if they are capable of being powered and are able to provide forced flow if required.

APPLICABILITY

In MODE 4, this LCO ensures forced circulation of the reactor coolant to remove decay heat from the core and to provide proper boron mixing. One loop of either RCS or RHR provides sufficient circulation for these purposes. However, two loops consisting of any combination of RCS and RHR loops are required to be OPERABLE to meet single failure considerations.

BASES

APPLICABILITY (continued)

Operation in other MODES is covered by:

LCO 3.4.4, "RCS Loops – MODES 1 and 2";
LCO 3.4.5, "RCS Loops – MODE 3";
LCO 3.4.7, "RCS Loops – MODE 5, Loops Filled";
LCO 3.4.8, "RCS Loops – MODE 5, Loops Not Filled";
LCO 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation – High Water Level" (MODE 6); and
LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation – Low Water Level" (MODE 6).

ACTIONS

A.1

If one required RCS loop is inoperable and two RHR loops are inoperable, redundancy for heat removal is lost. Action must be initiated to restore a second RCS or RHR loop to OPERABLE status. The immediate Completion Time reflects the importance of maintaining the availability of two paths for heat removal.

B.1

If one required RHR loop is OPERABLE and in operation and there are no RCS loops OPERABLE, an inoperable RCS or RHR loop must be restored to OPERABLE status to provide a redundant means for decay heat removal.

If the parameters that are outside the limits cannot be restored, the unit must be brought to MODE 5 within 24 hours. Bringing the unit to MODE 5 is a conservative action with regard to decay heat removal. With only one RHR loop OPERABLE, redundancy for decay heat removal is lost and, in the event of a loss of the only OPERABLE RHR loop, it would be safer to initiate that loss from MODE 5 (≤ 200°F) rather than MODE 4 (200 to 300°F). The Completion Time of 24 hours is a reasonable time, based on operating experience, to reach MODE 5 from MODE 4 in an orderly manner and without challenging plant systems.

BASES

ACTIONS (continued)

C.1 and C.2

If no loop is OPERABLE or in operation, except during conditions permitted by Note 1 in the LCO section, all operations involving a reduction of RCS boron concentration must be suspended and action to restore one RCS or RHR loop to OPERABLE status and in operation must be initiated. Boron dilution requires forced circulation for proper mixing, and the margin to criticality must not be reduced in this type of operation. The immediate Completion Times reflect the importance of maintaining operation for decay heat removal. The action to restore must be continued until one loop is restored to OPERABLE status and operation.

SURVEILLANCE REQUIREMENTS

SR 3.4.6.1

This SR requires verification every 12 hours that one RCS or RHR loop is in operation. Verification includes flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing heat removal. The Frequency of 12 hours is sufficient considering other indications and alarms available to the operator in the control room to monitor RCS and RHR loop performance.

SR 3.4.6.2

SR 3.4.6.2 requires verification of SG OPERABILITY. SG OPERABILITY is verified by ensuring that the actual secondary side water level is ≥ 71% (wide range equivalent) for each required loop. Depending on plant conditions, either wide range or narrow range SG level instruments may be used to verify this SR is met. Operators may be required to adjust the indicated level to compensate for the effects of SG temperature. If the SG secondary side actual water level is < 71%, the tubes may become uncovered and the associated loop may not be capable of providing the heat sink necessary for removal of decay heat. The 12 hour

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.6.2 (continued)

Frequency is considered adequate in view of other indications available in the control room to alert the operator to the loss of SG level.

SR 3.4.6.3

Verification that the required pump is OPERABLE ensures that an additional RCS or RHR pump can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power available to the required pump and associated support systems. The Frequency of 7 days is considered reasonable in view of other administrative controls available and has been shown to be acceptable by operating experience.

REFERENCES

1. FSAR Chapter 14.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.7 RCS Loops – MODE 5, Loops Filled

BASES

BACKGROUND

In MODE 5 with the RCS loops filled, the primary function of the reactor coolant is the removal of decay heat and transfer this heat either to the steam generator (SG) secondary side coolant, via natural circulation (Ref. 1), or the component cooling water via the residual heat removal (RHR) heat exchangers. While the principal means for decay heat removal is via the RHR System, the SGs, via natural circulation (Ref. 1), are specified as a backup means for redundancy. Even though the SGs cannot produce steam in this MODE, they are capable of being a heat sink due to their large contained volume of secondary water. As long as the SG secondary side water is at a lower temperature than the reactor coolant, heat transfer will occur. The rate of heat transfer is directly proportional to the temperature difference. The secondary function of the reactor coolant is to act as a carrier for soluble neutron poison, boric acid.

In MODE 5 with RCS loops filled, the reactor coolant is circulated by means of two RHR loops connected to the RCS, each loop containing an RHR heat exchanger, an RHR pump, and appropriate flow and temperature instrumentation for control, protection, and indication. One RHR pump circulates the water through the RCS at a sufficient rate to prevent boric acid stratification. The boron concentration in the pressurizer is of no concern because of the low pressurizer volume and because the pressurizer boron concentration will be higher than the rest of the reactor coolant.

Each RHR loop consists of one RHR pump and one RHR heat exchanger as well as associated piping and valves to transfer heat between the RHR heat exchanger and the core. Although either RHR heat exchanger may be credited for either RHR loop, one RHR heat exchanger must be OPERABLE for each OPERABLE RHR loop.

The number of loops in operation can vary to suit the operational needs. The intent of this LCO is to provide forced flow from at least one RHR loop for decay heat removal and transport. The flow provided by one RHR loop is adequate for decay heat removal.

BASES

BACKGROUND (Continued)

The other intent of this LCO is to require that a second path be available to provide redundancy for heat removal.

The LCO provides for redundant paths of decay heat removal capability. The first path can be an RHR loop that must be OPERABLE and in operation. The second path can be another OPERABLE RHR loop or maintaining one SG with secondary side water level ≥ 71% (wide range equivalent) to provide an alternate method for decay heat removal via natuaral circulation (Ref. 1).

When using a SG depending on natural circulation as the backup decay heat removal system in Mode 5, consideration should be given to the potential need for the following: (1) the ability to pressurize and control pressure in the RCS, (2) secondary side water level in the SG relied upon for decay heat removal, (3) availability of a supply of feedwater, and (4) availability of an auxiliary feedwater pump capable of injecting into the relied-upon SG (Ref.1).

During natural circulation, the SG secondary side water may boil creating the need to release steam through the atmospheric relief valves or other openings that may exist during shutdown conditions. Therefore, consideration should be given to avoiding the potential for pressurization of the SG secondary side. It is also important to note that during the decay heat removal using natural circulation, a MODE change (MODE 5 to MODE 4) could occur due to heat up of the RCS (Ref.1).

APPLICABLE SAFETY ANALYSES

In MODE 5, RCS circulation is considered in the determination of the time available for mitigation of the accidental boron dilution event. The RHR loops provide this circulation.

RCS Loops – MODE 5 (Loops Filled) satisfy Criterion 4 of 10 CFR 50.36.

BASES

LCO

The purpose of this LCO is to require that at least one of the RHR loops be OPERABLE and in operation with an additional RHR loop OPERABLE or one SG with secondary side water level ≥ 71% (wide range equivalent). One RHR loop provides sufficient forced circulation to perform the safety functions of the reactor coolant under these conditions. An additional RHR loop is required to be OPERABLE to meet single failure considerations. However, if the standby RHR loop is not OPERABLE, an acceptable alternate method is one SG with secondary side water level ≥ 71% (wide range equivalent). Should the operating RHR loop fail, the SG could be used to remove the decay heat via natural circulation.

Note 1 permits all RHR pumps to not be in operation ≤ 1 hour per 8 hour period. The purpose of the Note is to permit testing and maintenance that can be performed only when in MODE 5 with no forced circulation. This allowance is acceptable because operating experience has shown that boron stratification is not likely during this short period with no forced flow.

Utilization of Note 1 is permitted provided the following conditions are met, along with any other conditions imposed by maintenance or test procedures:

a. No operations are permitted that would dilute the RCS boron concentration, therefore maintaining the margin to criticality. Boron reduction is prohibited because a uniform concentration distribution throughout the RCS cannot be ensured when in natural circulation; and

b. Core outlet temperature is maintained ≥ 10°F below saturation temperature, so that no vapor bubble may form and possibly cause a natural circulation flow obstruction.

Note 2 allows one RHR loop to be inoperable for a period of up to 2 hours, provided that the other RHR loop is OPERABLE and in operation. This permits periodic surveillance tests to be performed on the inoperable loop during MODE 5 with no forced circulation.

BASES

LCO (continued)

Note 3 requires that the reactor coolant pump starting requirements of LCO 3.4.12, Low Temperature Overpressure Protection (LTOP), must be met before the start of a reactor coolant pump (RCP) with an RCS cold leg temperature less than the LTOP arming temperature specified in LCO 3.4.12, Low Temperature Overpressure Protection (LTOP), are met. This restriction is to prevent a low temperature overpressure event due to a thermal transient when an RCP is started.

Note 4 provides for an orderly transition from MODE 5 to MODE 4 during a planned heatup by permitting removal of RHR loops from operation when at least one RCS loop is in operation. This Note provides for the transition to MODE 4 where an RCS loop is permitted to be in operation and replaces the RCS circulation function provided by the RHR loops.

RHR pumps are OPERABLE if they are capable of being powered and are able to provide flow if required. An OPERABLE SG can perform as a heat sink with forced flow or natural circulation when it has an adequate water level and is OPERABLE in accordance with the Steam Generator Tube Surveillance Program.

If the SG being credited as the redundant method of decay heat removal depends on natural circulation (Ref.1), the SG is considered OPERABLE only if:

a. RCS loop and reactor pressure vessel filling and venting are complete; and,

b. RCS pressure has been maintained $\geq$ 100 psig since the most recent filling and venting.

APPLICABILITY

In MODE 5 with RCS loops filled, this LCO requires forced circulation of the reactor coolant to remove decay heat from the core and to provide proper boron mixing. One loop of RHR provides sufficient circulation for these purposes. However, one additional RHR loop is required to be OPERABLE, or the actual

BASES

APPLICABILITY (continued)

secondary side water level of at least one SG is required to be ≥ 71% (wide range equivalent).

Operation in other MODES is covered by:

LCO 3.4.4, "RCS Loops – MODES 1 and 2";
LCO 3.4.5, "RCS Loops – MODE 3";
LCO 3.4.6, "RCS Loops – MODE 4";
LCO 3.4.8, "RCS Loops – MODE 5, Loops Not Filled";
LCO 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation – High Water Level" (MODE 6); and
LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation – Low Water Level" (MODE 6).

ACTIONS

A.1 and A.2

If one RHR loop is inoperable and the required SG has secondary side water level < 71% (wide range equivalent) redundancy for heat removal is lost. Action must be initiated immediately to restore a second RHR loop to OPERABLE status or to restore the required SG secondary side water level. Either Required Action A.1 or Required Action A.2 will restore redundant heat removal paths. The immediate Completion Time reflects the importance of maintaining the availability of two paths for heat removal.

B.1 and B.2

If no RHR loop is in operation, except during conditions permitted by Note 1, or if no loop is OPERABLE, all operations involving a reduction of RCS boron concentration must be suspended and action to restore one RHR loop to OPERABLE status and in operation must be initiated. To prevent boron dilution, forced circulation is required to provide proper mixing and preserve the margin to criticality in this type of operation. The immediate Completion Times reflect the importance of maintaining operation for heat removal.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.7.1

This SR requires verification every 12 hours that the required loop is in operation. Verification includes flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing heat removal. The Frequency of 12 hours is sufficient considering other indications and alarms available to the operator in the control room to monitor RHR loop performance.

SR 3.4.7.2

Verifying that at least one SG is OPERABLE by ensuring the secondary side water level ≥ 71% (wide range equivalent) ensures an alternate decay heat removal method, via natural circulation, in the event that the second RHR loop is not OPERABLE. If both RHR loops are OPERABLE, this Surveillance is not needed. The 12 hour Frequency is considered adequate in view of other indications available in the control room to alert the operator to the loss of SG level.

SR 3.4.7.3

Verification that a second RHR pump is OPERABLE ensures that an additional pump can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power available to the RHR pump. If secondary side water level is ≥ 71% (wide range equivalent) in at least one SG, this Surveillance is not needed. The Frequency of 7 days is considered reasonable in view of other administrative controls available and has been shown to be acceptable by operating experience.

BASES

REFERENCES

1. NRC Information Notice 95-35, "Degraded Ability of Steam Generators to Remove Decay Heat by Natural Circulation."

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.8 RCS Loops – MODE 5, Loops Not Filled

BASES

BACKGROUND

In MODE 5 with the RCS loops not filled, the primary function of the reactor coolant is the removal of decay heat generated in the fuel, and the transfer of this heat to the component cooling water via the residual heat removal (RHR) heat exchangers. The steam generators (SGs) are not available as a heat sink when the loops are not filled. The secondary function of the reactor coolant is to act as a carrier for the soluble neutron poison, boric acid.

In MODE 5 with loops not filled, only RHR pumps can be used for coolant circulation. The number of pumps in operation can vary to suit the operational needs. The intent of this LCO is to provide forced flow from at least one RHR pump for decay heat removal and transport and to require that two loops be available to provide redundancy for heat removal.

Each RHR loop consists of one RHR pump and one RHR heat exchanger as well as associated piping and valves to transfer decay heat between the RHR heat exchanger and the core. Although either RHR heat exchanger may be credited for either RHR loop, one RHR heat exchanger must be OPERABLE for each OPERABLE RHR loop.

APPLICABLE SAFETY ANALYSES

In MODE 5, RCS circulation is considered in the determination of the time available for mitigation of the accidental boron dilution event. The RHR loops provide this circulation. The flow provided by one RHR loop is adequate for heat removal and for boron mixing.

RCS loops in MODE 5 (loops not filled) satisfy Criterion 4 of 10 CFR 50.36.

BASES

LCO

The purpose of this LCO is to require that at least two RHR loops be OPERABLE and one of these loops be in operation. An OPERABLE loop is one that has the capability of transferring heat from the reactor coolant at a controlled rate. Heat cannot be removed via the RHR System unless forced flow is used. A minimum of one running RHR pump meets the LCO requirement for one loop in operation. An additional RHR loop is required to be OPERABLE to meet redundancy considerations.

Note 1 permits all RHR pumps to not be in operation for ≤ 15 minutes. The circumstances for stopping both RHR pumps are to be limited to situations when the outage time is short and core outlet temperature is maintained ≥ 10°F below saturation temperature. The Note prohibits boron dilution or draining operations when RHR forced flow is stopped.

Note 2 allows one RHR loop to be inoperable for a period of ≤ 2 hours, provided that the other loop is OPERABLE and in operation. This permits periodic surveillance tests to be performed on the inoperable loop when in MODE 5.

An OPERABLE RHR loop is comprised of an OPERABLE RHR pump capable of providing forced flow to an OPERABLE RHR heat exchanger. RHR pumps are OPERABLE if they are capable of being powered and are able to provide flow if required.

APPLICABILITY

In MODE 5 with loops not filled, this LCO requires core heat removal and coolant circulation by the RHR System.

Operation in other MODES is covered by:

LCO 3.4.4, "RCS Loops – MODES 1 and 2";
LCO 3.4.5, "RCS Loops – MODE 3";
LCO 3.4.6, "RCS Loops – MODE 4";
LCO 3.4.7, "RCS Loops – MODE 5, Loops Filled";
LCO 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation – High Water Level" (MODE 6); and
LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation – Low Water Level" (MODE 6).

BASES

ACTIONS

A.1

If only one RHR loop is OPERABLE and in operation, redundancy for RHR is lost. Action must be initiated to restore a second loop to OPERABLE status. The immediate Completion Time reflects the importance of maintaining the availability of two loops for heat removal.

B.1 and B.2

If no required RHR loops are OPERABLE or in operation, except during conditions permitted by Note 1, all operations involving a reduction of RCS boron concentration must be suspended and action must be initiated immediately to restore an RHR loop to OPERABLE status and operation. Boron dilution requires forced circulation for uniform dilution. When required RHR loops are not OPERABLE or in operation, the margin to criticality must not be reduced. The immediate Completion Time reflects the importance of maintaining operation for heat removal. The action to restore must continue until one loop is restored to OPERABLE status and operation.

SURVEILLANCE REQUIREMENTS

SR 3.4.8.1

This SR requires verification every 12 hours that one loop is in operation. Verification includes flow rate, temperature, or pump status monitoring, which help ensure that forced flow is providing heat removal. The Frequency of 12 hours is sufficient considering other indications and alarms available to the operator in the control room to monitor RHR loop performance.

SR 3.4.8.2

Verification that the required number of pumps are OPERABLE ensures that additional pumps can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power available to the required pumps. The Frequency of 7 days is considered reasonable in view of other

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.8.2 (continued)

administrative controls available and has been shown to be acceptable by operating experience.

REFERENCES

None.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.9 Pressurizer

BASES

BACKGROUND

The pressurizer provides a point in the RCS where liquid and vapor are maintained in equilibrium under saturated conditions for pressure control purposes to prevent bulk boiling in the remainder of the RCS. Key functions include maintaining required primary system pressure during steady state operation, and limiting the pressure changes caused by reactor coolant thermal expansion and contraction during normal load transients.

The pressure control components addressed by this LCO include the pressurizer water level, the required heaters, and emergency power supplies. Pressurizer safety valves and pressurizer power operated relief valves are addressed by LCO 3.4.10, "Pressurizer Safety Valves," and LCO 3.4.11, "Pressurizer Power Operated Relief Valves (PORVs)," respectively.

The intent of the LCO is to ensure that a steam bubble exists in the pressurizer prior to power operation to minimize the consequences of potential overpressure transients. The presence of a steam bubble is consistent with analytical assumptions. Relatively small amounts of noncondensible gases can inhibit the condensation heat transfer between the pressurizer spray and the steam, and diminish the spray effectiveness for pressure control.

Electrical immersion heaters, located in the lower section of the pressurizer vessel, keep the water in the pressurizer at saturation temperature and maintain a constant operating pressure. A minimum required available capacity of pressurizer heaters ensures that the RCS pressure can be maintained. The capability to maintain and control system pressure is important for maintaining subcooled conditions in the RCS and ensuring the capability to remove core decay heat by either forced or natural circulation of reactor coolant. Unless adequate heater capacity is available, the hot, high pressure condition cannot be maintained indefinitely and still provide the required subcooling margin in the primary system. Inability to control the system pressure and maintain subcooling under conditions of natural circulation flow in the primary system could lead to a loss of

BASES

BACKGROUND (Continued)

single phase natural circulation and decreased capability to remove core decay heat.

Pressurizer heaters are powered from either the offsite source or the diesel generators (DGs) through the four 480V vital buses as follows: bus 2A (DG 31) supports 485 kW of pressurizer heaters; bus 3A (DG 31) supports 555 kW of pressurizer heaters; bus 5A (DG 33) supports 485 kW of pressurizer heaters; and, bus 6A (DG 32) supports 277 kW of pressurizer heaters.

APPLICABLE SAFETY ANALYSES

In MODES 1, 2, and 3, the LCO requirement for a steam bubble is reflected implicitly in the accident analyses. Safety analyses performed for lower MODES are not limiting. All analyses performed from a critical reactor condition assume the existence of a steam bubble and saturated conditions in the pressurizer. In making this assumption, the analyses neglect the small fraction of noncondensible gases normally present.

Safety analyses presented in the FSAR (Ref. 1) do not take credit for pressurizer heater operation; however, an implicit initial condition assumption of the safety analyses is that the RCS is operating at normal pressure.

The maximum pressurizer water level limit, which ensures that a steam bubble exists in the pressurizer, satisfies Criterion 2 of 10 CFR 50.36. Although the heaters are not specifically used in accident analysis, the need to maintain subcooling in the long term during loss of offsite power, as indicated in NUREG-0737 (Ref. 2), is the reason for providing an LCO.

LCO

The LCO requirement for the pressurizer to be OPERABLE with water level less than or equal to 92%, ensures that a steam bubble exists. Limiting the LCO maximum operating water level preserves the steam space for pressure control. The LCO has been

BASES

LCO (continued)

established to ensure the capability to establish and maintain pressure control for steady state operation and to minimize the consequences of potential overpressure transients. Requiring the presence of a steam bubble is also consistent with analytical assumptions.

The LCO requires two groups of OPERABLE pressurizer heaters, each with a capacity ≥ 150 kW, capable of being powered from either the offsite power source or the emergency power supply. Each of the 2 groups of pressurizer heaters must be powered from a different DG to ensure that the minimum required capacity of 150 kW can be energized during a loss of offsite power condition assuming the failure of a single DG. The minimum heater capacity required is sufficient to maintain the RCS near normal operating pressure when accounting for heat losses through the pressurizer insulation. By maintaining the pressure near the operating conditions, a wide margin to subcooling can be obtained in the loops. The value of 150 kW is sufficient to maintain pressure and is dependent on the heat losses.

APPLICABILITY

The need for pressure control is most pertinent when core heat can cause the greatest effect on RCS temperature, resulting in the greatest effect on pressurizer level and RCS pressure control. Thus, applicability has been designated for MODES 1 and 2. The applicability is also provided for MODE 3. The purpose is to prevent solid water RCS operation during heatup and cooldown to avoid rapid pressure rises caused by normal operational perturbation, such as reactor coolant pump startup.

In MODES 1, 2, and 3, there is need to maintain the availability of pressurizer heaters, capable of being powered from an emergency power supply. In the event of a loss of offsite power, the initial conditions of these MODES give the greatest demand for maintaining the RCS in a hot pressurized condition with loop subcooling for an extended period. For MODE 4, 5, or 6, it is not necessary to control pressure (by heaters) to ensure loop subcooling for heat transfer when the Residual Heat Removal (RHR) System is in service, and therefore, the LCO is not applicable.

BASES

ACTIONS

A.1 and A.2

Pressurizer water level control malfunctions or other plant evolutions may result in a pressurizer water level above the nominal upper limit, even with the plant at steady state conditions. Normally the plant will trip in this event since the upper limit of this LCO is the same as the Pressurizer Water Level – High Trip.

If the pressurizer water level is not within the limit, action must be taken to place the plant in a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to MODE 3, with the reactor trip breakers open, within 6 hours and to MODE 4 within 12 hours. This takes the unit out of the applicable MODES.

The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

B.1

If one required group of pressurizer heaters is inoperable, restoration is required within 72 hours. The Completion Time of 72 hours is reasonable considering that the redundant heater group is still available and the low probability of an event during this period. Pressure control may be maintained during this time using remaining heaters.

C.1 and C.2

If one group of pressurizer heaters are inoperable and cannot be restored in the allowed Completion Time of Required Action B.1, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 6 hours and to MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.9.1

This SR requires that during steady state operation, pressurizer level is maintained below the nominal upper limit to provide a minimum space for a steam bubble. The Surveillance is performed by observing the indicated level. The Frequency of 12 hours has been shown by operating practice to be sufficient to regularly assess level for any deviation and verify that operation is within safety analyses assumptions of ensuring that a steam bubble exists in the pressurizer. Alarms are also available for early detection of abnormal level indications.

SR 3.4.9.2

The SR is satisfied when the power supplies are demonstrated to be capable of producing the minimum power and the associated pressurizer heaters are verified to be at their design rating. This may be done separately by testing the power supply output and by performing an electrical check on heater element continuity and resistance. The Frequency of 24 months is considered adequate to detect heater degradation and has been shown by operating experience to be acceptable.

REFERENCES

1. FSAR, Section 14.
2. NUREG-0737, November 1980.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.10 Pressurizer Safety Valves

BASES

BACKGROUND

The pressurizer safety valves provide, in conjunction with the Reactor Protection System, overpressure protection for the RCS. The pressurizer safety valves are totally enclosed spring loaded, self actuated valves with backpressure compensation. The safety valves are designed to prevent the system pressure from exceeding the system Safety Limit (SL), 2735 psig, which is 110% of the design pressure.

Because the safety valves are totally enclosed and self actuating, they are considered independent components. The relief capacity for each valve, 420,000 lb/hr, is based on postulated overpressure transient conditions resulting from a complete loss of steam flow to the turbine without a direct reactor trip or any other control. This event results in the maximum surge rate into the pressurizer, which specifies the minimum relief capacity for the safety valves. The discharge flow from the pressurizer safety valves is directed to the pressurizer relief tank. This discharge flow is indicated by an increase in temperature downstream of the pressurizer safety valves; or an increase in the pressurizer relief tank temperature or level; or actuation of acoustic monitors.

Overpressure protection is required in MODES 1, 2, 3, 4, and 5; however, in MODE 4, with the average of the RCS cold leg temperatures less than the LTOP arming temperature specified in LCO 3.4.12, and MODE 5 and MODE 6 with the reactor vessel head on, overpressure protection is provided by operating procedures and by meeting the requirements of LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP) System."

The upper and lower pressure limits are based on the ± 1% tolerance requirement (Ref. 1) for lifting pressures above 1000 psig. The lift setting is for the ambient conditions associated with MODES 1, 2, and 3. This requires either that the valves be set hot or that a correlation between hot and cold settings be established.

BASES

BACKGROUND (Continued)

Although the pressurizer safety valves must be set to ± 1% during the Surveillance, the pressurizer safety valves satisfy safety analysis assumptions and meet ASME Code requirements if the setpoint is determined to be ± 3% at the end of the surveillance interval. Therefore, the pressurizer safety valve setpoint is ± 3% for OPERABILITY; however, the valves must be reset to ± 1% during the Surveillance to allow for drift.

The pressurizer safety valves are part of the primary success path and mitigate the effects of postulated accidents. OPERABILITY of the safety valves ensures that the RCS pressure will be limited to 110% of design pressure. The consequences of exceeding the American Society of Mechanical Engineers (ASME) pressure limit (Ref. 1) could include damage to RCS components, increased leakage, or a requirement to perform additional stress analyses prior to resumption of reactor operation.

APPLICABLE SAFETY ANALYSES

All accident and safety analyses in the FSAR (Ref. 2) that require safety valve actuation assume operation of three pressurizer safety valves to limit increases in RCS pressure. No single failure is assumed for spring loaded safety valves designed in accordance with the ASME Boiler and Pressure Vessel Code. The overpressure protection analysis (Ref. 3) is also based on operation of three safety valves. Accidents that could result in overpressurization if not properly terminated include:

a. Uncontrolled rod withdrawal from full power;

b. Loss of reactor coolant flow;

c. Loss of external electrical load;

d. Loss of normal feedwater;

e. Loss of all AC power to station auxiliaries; and

BASES

APPLICABLE SAFETY ANALYSES (continued)

f. Locked rotor.

Detailed analyses of the above transients are contained in Reference 2. Safety valve actuation may be required in events a, b, c, e, and f (above) to limit the pressure increase. Compliance with this LCO is consistent with the design bases and accident analyses assumptions. The pressurizer safety valves satisfy safety analysis assumptions and meet ASME Code requirements if the setpoint is determined to be ± 3% at the end of the surveillance interval.

Pressurizer safety valves satisfy Criterion 3 of 10 CFR 50.36.

LCO

The three pressurizer safety valves are set to open at the RCS design pressure (2500 psia), and within the ASME specified tolerance, to avoid exceeding the maximum design pressure SL, to maintain accident analyses assumptions, and to comply with ASME requirements. The upper and lower pressure tolerance limits are based on the ± 1% tolerance requirements (Ref. 1) for lifting pressures above 1000 psig.

The pressurizer safety valve setpoint is ± 3% of the nominal 2485 psig setpoint for OPERABILITY; however, the valves must be reset to ± 1% of the nominal 2485 psig setpoint during the Surveillance to allow for drift during the SR interval.

The limit protected by this Specification is the reactor coolant pressure boundary (RCPB) SL of 110% of design pressure. Inoperability of one or more valves could result in exceeding the SL if a transient were to occur. The consequences of exceeding the ASME pressure limit could include damage to one or more RCS components, increased leakage, or additional stress analysis being required prior to resumption of reactor operation.

BASES

APPLICABILITY

In MODES 1, 2, and 3, and portions of MODE 4 above the LTOP arming temperature, OPERABILITY of three valves is required because the combined capacity is required to keep reactor coolant pressure below 110% of its design value during certain accidents. MODE 3 and portions of MODE 4 are conservatively included, although the listed accidents may not require the safety valves for protection.

The LCO is not applicable in MODE 4 when the average of the RCS cold leg temperatures are less than the OPS arming temperature specified in LCO 3.4.12 or in MODE 5 because LTOP is provided. Overpressure protection is not required in MODE 6 with reactor vessel head removed.

The Note allows entry into MODES 3 and 4 with the lift settings outside the LCO limits. This permits testing and examination of the safety valves at high pressure and temperature near their normal operating range, but only after the valves have had a preliminary cold setting. The cold setting gives assurance that the valves are OPERABLE near their design condition. Only one valve at a time will be removed from service for testing. The 54 hour exception is based on 18 hour outage time for each of the three valves. The 18 hour period is derived from industry experience that hot testing can be performed in this timeframe.

ACTIONS

A.1

With one pressurizer safety valve inoperable, restoration must take place within 15 minutes. The Completion Time of 15 minutes reflects the importance of maintaining the RCS overpressure protection. An inoperable safety valve coincident with an RCS overpressure event could challenge the integrity of the pressure boundary.

B.1 and B.2

If the Required Action of A.1 cannot be met within the required Completion Time or if two or more pressurizer safety valves are inoperable, the plant must be brought to a MODE in which the

BASES

ACTIONS

B.1 and B.2 (continued)

requirement does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 4 with the average of the RCS cold leg temperatures less than the OPS arming temperature specified in LCO 3.4.12 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems. With the average of the RCS cold leg temperatures less than the OPS arming temperature specified in LCO 3.4.12, overpressure protection is provided by LTOP. The change from MODE 1, 2, or 3 to MODE 4 reduces the RCS energy (core power and pressure), lowers the potential for large pressurizer insurges, and thereby removes the need for overpressure protection by three pressurizer safety valves.

SURVEILLANCE REQUIREMENTS

SR 3.4.10.1

SRs are specified in the Inservice Testing Program. Pressurizer safety valves are to be tested in accordance with the requirements of Section XI of the ASME Code (Ref. 4), which provides the activities and Frequencies necessary to satisfy the SRs. No additional requirements are specified.

The pressurizer safety valve setpoint is ± 3% for OPERABILITY; however, the valves are reset to ± 1% during the Surveillance to allow for drift.

BASES

REFERENCES

1. ASME, Boiler and Pressure Vessel Code, Section III.
2. FSAR, Chapter 14.
3. WCAP-7769, Rev. 1, June 1972.
4. ASME, Boiler and Pressure Vessel Code, Section XI.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.11 Pressurizer Power Operated Relief Valves (PORVs)

BASES

BACKGROUND

The pressurizer is equipped with two types of devices for pressure relief: pressurizer safety valves and PORVs. The PORVs are nitrogen operated valves that are controlled to open at a specific set pressure when the pressurizer pressure increases and close when the pressurizer pressure decreases. The PORVs may also be manually operated from the control room.

Block valves, which are normally open, are located between the pressurizer and the PORVs. The block valves are used to isolate the PORVs in case of excessive leakage or a stuck open PORV. Block valve closure is accomplished manually using controls in the control room. A stuck open PORV is, in effect, a small break loss of coolant accident (LOCA). As such, block valve closure terminates the RCS depressurization and coolant inventory loss.

The PORVs and their associated block valves may be used by plant operators to depressurize the RCS to recover from certain transients if normal and alternate pressurizer spray is not available. Additionally, the series arrangement of the PORVs and their block valves permit performance of surveillances on the valves during power operation.

The PORVs may also be used for feed and bleed core cooling in the case of multiple equipment failure events that are not within the design basis, such as a total loss of feedwater.

Electrical power neeeded to support the PORVs, their block valves, and their controls is supplied from the vital buses that normally receive power from offsite power sources, but is also capable of being supplied from emergency power sources in the event of a loss of offsite power. Two PORVs and their associated block valves are powered from two separate safety trains (Ref. 1).

The plant has two PORVs, each having a design relief capacity of 179,000 lb/hr at 2335 psig. The functional design of the PORVs is based on maintaining pressure below the Pressurizer

BASES

BACKGROUND (Continued)

Pressure – High reactor trip setpoint following a step reduction of 50% of full load with steam dump and automatic reactor control operation. In addition, the PORVs minimize challenges to the pressurizer safety valves and also may be used for low temperature overpressure protection (LTOP). See LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP) System."

APPLICABLE SAFETY ANALYSES

Plant operators employ the PORVs to depressurize the RCS in response to certain plant transients if normal and alternate pressurizer spray are not available. For the Steam Generator Tube Rupture (SGTR) event, the safety analysis assumes that manual operator actions are required to mitigate the event. A loss of offsite power is assumed to accompany the event, and thus, normal pressurizer spray is unavailable to reduce RCS pressure. The PORVs or auxiliary spray are assumed to be used for RCS depressurization, which is one of the steps performed to equalize the primary and secondary pressures in order to terminate the primary to secondary break flow and the radioactive releases from the affected steam generator.

The PORVs are modeled in safety analyses for events that result in increasing RCS pressure for which departure from nucleate boiling ratio (DNBR) criteria are critical (Ref. 2). By assuming PORV manual actuation, the DNBR calculation is more conservative although not required to meet safety limits. As such, this actuation is not required to mitigate these events, and PORV automatic operation is not an assumed safety function.

Pressurizer PORVs satisfy Criterion 3 of 10 CFR 50.36.

LCO

The LCO requires the PORVs and their associated block valves to be OPERABLE for manual operation to mitigate the effects associated with an SGTR.

LCO (continued)

By maintaining two PORVs and their associated block valves OPERABLE, the single failure criterion is satisfied. An OPERABLE block valve may be either open, or closed and energized with the capability to be opened, since the required safety function is accomplished by manual operation. Although typically open to allow PORV operation, the block valves may be OPERABLE when closed to isolate the flow path of an inoperable PORV that is capable of being manually cycled (e.g., as in the case of excessive PORV leakage). Similarly, isolation of an OPERABLE PORV does not render that PORV or block valve inoperable provided the relief function remains available with manual action.

An OPERABLE PORV is required to be capable of manually opening and closing, and not experiencing excessive seat leakage. Excessive seat leakage, although not associated with a specific acceptance criteria, exists when conditions dictate closure of the block valve to limit leakage. Satisfying the LCO helps minimize challenges to fission product barriers.

APPLICABILITY

In MODES 1, 2, and 3, the PORV and its block valve are required to be OPERABLE to limit the potential for a small break LOCA through the flow path. The most likely cause for a PORV small break LOCA is a result of a pressure increase transient that causes the PORV to open. Imbalances in the energy output of the core and heat removal by the secondary system can cause the RCS pressure to increase to the PORV opening setpoint. The most rapid increases will occur at the higher operating power and pressure conditions of MODES 1 and 2. The PORVs are also required to be OPERABLE in MODES 1, 2, and 3 for manual actuation to mitigate a steam generator tube rupture event.

Pressure increases are less prominent in MODE 3 because the core input energy is reduced, but the RCS pressure is high. Therefore, the LCO is applicable in MODES 1, 2, and 3. The LCO is not applicable in MODE 4 when both pressure and core energy are decreased and the pressure surges become much less significant. The PORV setpoint is reduced for LTOP in MODES 4,

BASES

APPLICABILITY (continued)

5, and 6 with the reactor vessel head in place. LCO 3.4.12 addresses the PORV requirements in these MODES.

ACTIONS

Note 1 has been added to clarify that all pressurizer PORVs are treated as separate entities, each with separate Completion Times (i.e., the Completion Time is on a component basis). The exception for LCO 3.0.4, Note 2, permits entry into MODES 1, 2, and 3. This exception to LCO requirements is normally used to perform cycling of the PORVs or block valves to verify their OPERABLE status because testing is not performed in lower MODES.

A.1

PORVs may be inoperable and capable of being manually cycled (e.g., excessive seat leakage). In this condition, either the PORVs must be restored or the flow path isolated within 1 hour. The associated block valve is required to be closed, but power must be maintained to the associated block valve, since removal of power would render the block valve inoperable. This permits operation of the plant until the next refueling outage (MODE 6) so that maintenance can be performed on the PORVs to eliminate the problem condition. Normally, the PORVs should be available for automatic mitigation of overpressure events and should be returned to OPERABLE status prior to entering startup (MODE 2).

Quick access to the PORV for pressure control can be made when power remains on the closed block valve. The Completion Time of 1 hour is based on plant operating experience that has shown that minor problems can be corrected or closure accomplished in this time period.

B.1, B.2, and B.3

If one PORV is inoperable and not capable of being manually cycled, it must be either restored, or isolated by closing the associated block valve and removing the power to the associated block valve. The Completion Time of 1 hour is reasonable, based on challenges to the PORVs during this time period, and provide

BASES

ACTIONS

B.1, B.2, and B.3 (continued)

the operator adequate time to correct the situation. If the inoperable valve cannot be restored to OPERABLE status, it must be isolated within the specified time. Because there is at least one PORV that remains OPERABLE, an additional 7 days is provided to restore the inoperable PORV to OPERABLE status. If the PORV cannot be restored within this additional time, the plant must be brought to a MODE in which the LCO does not apply, as required by Condition D.

C.1 and C.2

If one block valve is inoperable, then it is necessary to either restore the block valve to OPERABLE status within the Completion Time of 1 hour or place the associated PORV in the closed position (i.e., switch in manual control). The prime importance for the capability to close the block valve is to isolate a stuck open PORV. Therefore, if the block valve cannot be restored to OPERABLE status within 1 hour, the Required Action is to place the PORV in manual control to preclude its automatic opening for an overpressure event and to avoid the potential for a stuck open PORV at a time that the block valve is inoperable. The Completion Time of 1 hour is reasonable, based on the small potential for challenges to the system during this time period, and provides the operator time to correct the situation. Because at least one PORV remains OPERABLE, the operator is permitted a Completion Time of 7 days to restore the inoperable block valve to OPERABLE status. The time allowed to restore the block valve is based upon the Completion Time for restoring an inoperable PORV in Condition B, since the PORVs may not be capable of mitigating an overpressure event if the inoperable block valve is not full open. If the block valve is restored within the Completion Time of 7 days, the power will be restored and the PORV restored. If it cannot be restored within this additional time, the plant must be brought to a MODE in which the LCO does not apply, as required by Condition D.

D.1 and D.2

If the Required Action of Condition A, B, or C is not met, then the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at

ACTIONS

D.1 and D.2 (continued)

least MODE 3 within 6 hours and to MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems. In MODES 4 and 5, maintaining PORV OPERABILITY may be required. See LCO 3.4.12.

E.1, E.2, E.3 and E.4

If more than one PORV is inoperable and not capable of being manually cycled, it is necessary to either restore at least one valve within the Completion Time of 1 hour or isolate the flow path by closing and removing the power to the associated block valves. The Completion Time of 1 hour is reasonable, based on the small potential for challenges to the system during this time and provides the operator time to correct the situation. If no PORVs are restored within the Completion Time, then the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems. In MODES 4 and 5, maintaining PORV OPERABILITY may be required. See LCO 3.4.12.

F.1 and F.2

If more than one block valve is inoperable, it is necessary to either restore the block valves within the Completion Time of 1 hour, or place the associated PORVs in manual control (i.e., closed position) and restore at least one block valve within 2 hours. The Completion Times are reasonable, based on the small potential for challenges to the system during this time and provide the operator time to correct the situation.

G.1 and G.2

If the Required Actions of Condition F are not met, then the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least

BASES

ACTIONS

G.1 and G.2 (continued)

MODE 3 within 6 hours and to MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems. In MODES 4 and 5, maintaining PORV OPERABILITY may be required. See LCO 3.4.12.

SURVEILLANCE REQUIREMENTS

SR 3.4.11.1

Block valve cycling verifies that the valve(s) can be opened and closed if needed. The basis for the Frequency of 92 days is the ASME Code, Section XI (Ref. 3). If the block valve is closed to isolate a PORV that is capable of being manually cycled, the OPERABILITY of the block valve is important because opening the block valve is necessary to permit the PORV to be used for manual control of reactor pressure. If the block valve is closed to isolate an inoperable PORV that is not capable of being manually cycled, the maximum Completion Time to restore the PORV and open the block valve is 7 days, which is well within the allowable limits (25%) to extend the block valve Frequency of 92 days. Furthermore, these test requirements would be completed by the reopening of a recently closed block valve upon restoration of the PORV to OPERABLE status.

The Note modifies this SR by stating that it is not required to be met with the block valve closed, in accordance with the Required Action of this LCO.

SR 3.4.11.2

SR 3.4.11.2 requires a complete cycle of each PORV. Operating a PORV through one complete cycle ensures that the PORV can be manually actuated for mitigation of an SGTR. The Frequency of 24 months is based on a typical refueling cycle and industry accepted practice.

BASES

REFERENCES

1. Regulatory Guide 1.32, February 1977.

2. FSAR, Section 14.

3. ASME, Boiler and Pressure Vessel Code, Section XI.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.12 Low Temperature Overpressure Protection (LTOP)

BASES

BACKGROUND

LTOP is established to limit RCS pressure at low temperatures so the integrity of the reactor coolant pressure boundary (RCPB) is not compromised by violating the pressure and temperature (P/T) limits of 10 CFR 50, Appendix G (Ref. 1). The reactor vessel is the limiting RCPB component for demonstrating such protection. The PTLR provides the maximum allowable actuation logic setpoints for the power operated relief valves (PORVs) and the maximum RCS pressure for the existing RCS cold leg temperature during cooldown, shutdown, and heatup to meet the Reference 1 requirements during the LTOP MODES.

The reactor vessel material is less tough at low temperatures than at normal operating temperature. As the vessel neutron exposure accumulates, the material toughness decreases and becomes less resistant to pressure stress at low temperatures (Ref. 2). RCS pressure, therefore, is maintained low at low temperatures and is increased only as temperature is increased.

The potential for vessel overpressurization is most acute when the RCS is water solid, occurring only while shutdown because a pressure fluctuation can occur more quickly than an operator can react to relieve the condition. Exceeding the RCS P/T limits by a significant amount could cause brittle cracking of the reactor vessel. LCO 3.4.3, "RCS Pressure and Temperature (P/T) Limits," requires administrative control of RCS pressure and temperature during heatup and cooldown to prevent exceeding the PTLR limits.

The RHR System is protected from overpressure by a spring loaded relief valve (i.e., RV-1836) when the RHR System is isolated from the RCS. When the RHR System is not isolated from the RCS, the RHR System relief valve has sufficient capacity to accommodate all 3 charging pumps. However, this relief valve does not have sufficient capacity to ensure that the RHR system does not exceed design pressure limits during a mass addition resulting from an inadvertent injection of one or more high head safety injection (HHSI) pumps. Therefore, LTOP requirements are used to protect

BASES

BACKGROUND (Continued)

the RHR System whenever the RHR System is not isolated from the RCS.

This LCO provides RCS overpressure protection by limiting maximum coolant input capability and having adequate pressure relief capacity. Limiting coolant input capability is achieved by not permitting any High Head Safety Injection (HHSI) pumps to be capable of injection into the RCS and isolating the accumulators. The pressure relief capacity requires either two redundant power operated relief valves (PORVs) or a depressurized RCS and an RCS vent of sufficient size. One PORV or the open RCS vent is sufficient to provide overpressure protection to terminate an increasing pressure event. Alternately, if redundant PORVs are not Operable or an RCS vent cannot be established, LTOP protection may be established by limiting the pressurizer level to within limits specified in the PTLR consistent with the number of charging pumps and number of high head safety injection (HHSI) pumps capable of injecting into the RCS. This approach is acceptable because pressurizer level can be maintained such that it will either accommodate any anticipated pressure surge or allow operators time to react to any unanticipated pressure surge. When pressurizer level is used to satisfy LTOP requirements, operator action is assumed to terminate the unplanned HHSI pump injection within 10 minutes.

With high pressure coolant input capability limited, the ability to create an overpressure condition by coolant addition is restricted. The LCO does not require the makeup control system deactivated or the safety injection (SI) actuation circuits blocked. Due to the lower pressures in the LTOP MODES and the expected core decay heat levels, the makeup system can provide adequate flow via the makeup control valve. There is no restriction on the status of charging pumps when LTOP is established using either a PORV or an RCS vent. If conditions require the use of more than one HHSI pump for makeup in the event of loss of inventory, then pumps can be made available through manual actions. Charging pumps and low pressure injection systems are available to provide makeup even when LTOP requirements are applicable.

BASES

BACKGROUND (Continued)

When configured to provide low temperature overpressure protection, the PORVs are part of the Overpressure Protection System (OPS). LTOP for pressure relief can consist of either the OPS (two PORVs with reduced lift settings), or a depressurized RCS and an RCS vent of sufficient size. Two PORVs are required for redundancy. One PORV has adequate relieving capability to keep from overpressurization for the required coolant input capability.

PORV Requirements

The Overpressure Protection System (OPS) provides the low temperature overpressure protection by controlling the Power Operated Relief Valves (PORVs) and their associated block valves with pressure setpoints that vary with RCS cold leg temperature. Specifically, cold leg temperature signals from three RCS loops are supplied to three associated function generators that calculate the maximum RCS pressures allowed at those temperatures. The maximum RCS pressure limits at any RCS temperature correspond to the 10 CFR 50, Appendix G, limit curve maintained in the Pressure and Temperature Limits Report and are used as the OPS pressure setpoint. Having the setpoints of both valves within the limits in the PTLR ensures that the Reference 1 limits will not be exceeded in any analyzed event.

In addition to generating the OPS pressure setpoint, the same cold leg temperature signals are used to “arm” the OPS when RCS temperature falls below the temperature at which low temperature overpressure protection is required (319°F). Each PORV opens when a two-out-of-two (temperature and pressure) coincidence logic is satisfied. OPS is "armed" when RCS temperature falls below the temperature that satisfies one half of the two-out-of-two (temperature-pressure) coincidence logic. When OPS is enabled, the PORVs will open if RCS pressure exceeds the calculated pressure setpoint that varies with RCS temperature. The PORV block valves open when the RCS temperature falls below the OPS arming temperature. Note that the control switches for the PORV and PORV block valves must be in the AUTO position and the OPS states links closed for OPS signals to actuate the PORVs.

BASES

BACKGROUND (Continued)

Three channels of RCS cold leg temperature are used in the two-out-of-three coincidence logic to satisfy the temperature portion of the two-out-of-two (temperature and pressure) coincidence logic for each PORV. Three channels of RCS pressure are used in a two-out-of-three coincidence logic to satisfy the pressure portion of the two-out-of-two (temperature-pressure) coincidence logic for each PORV. Use of a two-out-of-three coincidence logic for pressure and for temperature ensures that a single failure will not cause or prevent an OPS actuation. Use of two PORVs, each with adequate relieving capability to prevent overpressurization, ensures that a single failure will not prevent an OPS actuation.

When a PORV is opened in an increasing pressure transient, the release of coolant will cause the pressure increase to slow and reverse. As the PORV releases coolant, the RCS pressure decreases until a reset pressure is reached and the valve is signaled to close. The pressure continues to decrease below the reset pressure as the valve closes.

RCS Vent Requirements

Once the RCS is depressurized, a vent exposed to the containment atmosphere will maintain the RCS at containment ambient pressure in an RCS overpressure transient, if the relieving requirements of the transient do not exceed the capabilities of the vent. Thus, the vent path must be capable of relieving the flow resulting from the limiting LTOP mass or heat input transient, and maintaining pressure below the P/T limits. The required vent capacity may be provided by one or more vent paths.

Multiple methods exist for establishing the required RCS vent capacity including removing or blocking open a PORV and disabling its block valve in the open position. An RCS vent of ≥ 2.00 square inches when no HHSI pump is capable of injecting into the RCS; or, an RCS vent with opening greater than or equal to one pressurizer code safety valve flange and up to two HHSI pumps capable of injecting into the RCS will satisfy LTOP requirements because either configuration ensures pressure limits are not exceed during a transient. Alternately, an RCS vent of ≥ 2.00

BASES

BACKGROUND (Continued)

square inches coupled with a pressurizer level ≤ 0% and up to two HHSI pumps capable of injecting into the RCS will satisfy LTOP requirements because it ensures a minimum of 10 minutes for operator action before pressure limits are exceeded during a transient. The vent path(s) must be above the level of reactor coolant, so as not to drain the RCS when open.

APPLICABLE SAFETY ANALYSES

Safety analyses (Ref. 3) demonstrate that the reactor vessel is adequately protected against exceeding the Reference 1 P/T limits. In MODES 1, 2, and 3, with RCS cold leg temperature exceeding 411°F, the pressurizer safety valves will prevent RCS pressure from exceeding the Reference 1 limits. At 319°F and below, overpressure prevention falls to two OPERABLE PORVs in conjunction with the Overpressure Protection System (OPS) or to a depressurized RCS and a sufficient sized RCS vent. Each of these means has a limited overpressure relief capability. Alternately, if redundant PORVs are not Operable, Low Temperature Overpressure protection may be maintained by limiting the pressurizer level to within limits specified in the PTLR consistent with the number of charging pumps and number of high head safety injection (HHSI) pumps capable of injecting into the RCS. This approach is acceptable because pressurizer level can be established to either accommodate any anticipated pressure surge or allow operators time to react to any unanticipated pressure surge.

When the RCS temperature is greater than the LTOP arming temperature (i.e., ≥ 319°F) but below the minimum temperature at which the pressurizer safety valves lift prior to violation of the 10 CFR 50, Appendix G, limits (i.e., ≤ 411°F), administrative controls in the Technical Requirements Manual (TRM) (Ref. 4) are used to limit the potential for exceeding 10 CFR 50, Appendix G, limits. These administrative controls may include operating with a bubble in the pressurizer and/or otherwise limiting plant time or activities when the RCS temperature is in the specified range. The use of administrative controls to govern operation above the LTOP arming temperature

BASES

APPLICABLE SAFETY ANALYSES (continued)

but below the minimum temperature at which the pressurizer safety valves lift prior to violation of the 10 CFR 50, Appendix G, limits is consistent with the guidance provided in Generic Letter 88-011, NRC Position on Radiation Embrittlement of Reactor Vessel Materials and its Impact on Plant Operations (Ref.2). GL 88-011 states that automatic, or passive, protection of the P-T limits will not be required but administratively controlled when in the upper end of the 10 CFR 50, Appendix G, temperature range.

The actual temperature at which the pressure in the P/T limit curve falls below the pressurizer safety valve setpoint increases as the reactor vessel material toughness decreases due to neutron embrittlement. Each time the PTLR curves are revised, LTOP must be re-evaluated to ensure its functional requirements can still be met using the OPS (PORVs) method or the depressurized and vented RCS condition.

The PTLR contains the acceptance limits that define the LTOP requirements. Any change to the RCS must be evaluated against the Ref. 3 analyses to determine the impact of the change on the LTOP acceptance limits.

Transients that are capable of overpressurizing the RCS are categorized as either mass or heat input transients, examples of which follow:

<u>Mass Input Type Transients</u>

a. Inadvertent safety injection; or

b. Charging/letdown flow mismatch.

<u>Heat Input Type Transients</u>

a. Inadvertent actuation of pressurizer heaters;

b. Loss of RHR cooling; or

BASES

APPLICABLE SAFETY ANALYSES (continued)

c. Reactor coolant pump (RCP) startup with temperature asymmetry within the RCS or between the RCS and steam generators.

The following are required during the LTOP MODES to ensure that mass and heat input transients do not occur. This is accomplished by the following:

a. Rendering all HHSI pumps incapable of injection;

b. Deactivating the accumulator discharge isolation valves in their closed positions or maintaining accumulator pressure less than the maximum RCS pressure for the existing RCS cold leg temperature allowed by the P/T limit curves provided in the PTLR; and

c. Disallowing start of an RCP unless conditions are established that ensure a RCP pump start will not cause a pressure excursion that will exceed LTOP limits. Required conditions for starting a RCP when LTOP is required include a combination of primary and secondary water temperature differences and Overpressure Protection System (OPS) status or pressurizer level. Meeting the LTOP RCP starting surveillances ensures that theses conditions are satisfied prior to a RCP pump start.

The Ref. 3 analyses demonstrate that either one PORV or the depressurized RCS and RCS vent can maintain RCS pressure below limits when no HHSI pump is capable of injecting into the RCS. This assumes an RCS vent of ≥ 2.00 square inches. The same protection can be provided when up to two HHSI pumps are capable of injecting into the RCS assuming an RCS vent with opening greater than or equal to one code pressurizer safety valve flange. Alternately, LTOP requirements can be satisfied by various combinations of pressurizer level, RCS pressure, and RCS injection capability (i.e., maximum number of HHSI pumps and/or charging pumps) shown in the PTLR. These combinations of pressurizer level, RCS pressure, and RCS injection capability satisfy LTOP requirements by ensuring a minimum of 10 minutes for operator action to terminate an unplanned event prior to

APPLICABLE SAFETY ANALYSES (continued)

exceeding maximum allowable RCS pressure. None of the analyses addressed the pressure transient need from accumulator injection, therefore, when RCS temperature is low, the LCO also requires the accumulator isolation when accumulator pressure is greater than or equal to the maximum RCS pressure for the existing RCS cold leg temperature allowed in the PTLR.

If the accumulators are isolated and not depressurized, then the accumulators must have their discharge valves closed and the valve power supply breakers fixed in their open positions.

Fracture mechanics analyses established the temperature of LTOP Applicability at 319°F.

The consequences of a loss of coolant accident (LOCA) in LTOP MODE 4 conform to 10 CFR 50.46 and 10 CFR 50, Appendix K (Refs. 5 and 6) requirements by having ECCS OPERABLE in accordance with requirements in LCO 3.5.3, ECCS-Shutdown.

PORV Performance

The fracture mechanics analyses show that the vessel is protected when the PORVs are set to open at or below the limit shown in the PTLR. The setpoints are derived by analyses that model the performance of the LTOP System, assuming the limiting LTOP transient with HHSI not injecting into the RCS. These analyses consider pressure overshoot and undershoot beyond the PORV opening and closing, resulting from signal processing and valve stroke times. The PORV setpoints at or below the derived limit ensures the Reference 1 P/T limits will be met. The OPS setpoint is based on a comparative analysis of Reference 3, with allowances for metal/fluid temperature differences, static head due to elevation differences, and dynamic head from the operation of the reactor coolant pumps and RHR pumps.

The PORV setpoints in the PTLR will be updated when the revised P/T limits conflict with the LTOP analysis limits. The P/T limits are periodically modified as the reactor vessel material toughness decreases due to neutron embrittlement caused by neutron irradiation. Revised limits are determined using neutron

BASES

APPLICABLE SAFETY ANALYSES (continued)

fluence projections and the results of examinations of the reactor vessel material irradiation surveillance specimens. The Bases for LCO 3.4.3, "RCS Pressure and Temperature (P/T) Limits," discuss these examinations.

The PORVs are considered active components. Thus, the failure of one PORV is assumed to represent the worst case, single active failure.

<u>RCS Vent Performance</u>

With the RCS depressurized, analyses show a vent size of 1.4 square inches is capable of mitigating the allowed LTOP overpressure transient assuming no HHSI pump and no accumulator injects into the RCS. The LCO limit for an RCS vent is conservatively established at 2.00 square inches. The capacity of a vent this size is greater than the flow of the limiting transient for the LTOP configuration, maintaining RCS pressure less than the maximum pressure on the P/T limit curve. An RCS vent with opening greater than or equal to one pressurizer code safety valve flange and up to two HHSI pumps capable of injecting into the RCS will satisfy LTOP requirements because it ensures pressure limits are not exceed during a transient. An RCS vent of ≥ 2.00 square inches coupled with a pressurizer level ≤ 0% and up to two HHSI pumps capable of injecting into the RCS will satisfy LTOP requirements because it ensures a minimum of 10 minutes for operator action before pressure limits are exceeded during a transient.

The RCS vent size will be re-evaluated for compliance each time the P/T limit curves are revised based on the results of the vessel material surveillance.

The RCS vent is passive and is not subject to active failure.

LTOP satisfies Criterion 2 of 10 CFR 50.36.

BASES

LCO

This LCO requires that LTOP is OPERABLE. LTOP is OPERABLE when the minimum coolant input and pressure relief capabilities are OPERABLE. Violation of this LCO could lead to the loss of low temperature overpressure mitigation and violation of the Reference 1 limits as a result of an operational transient.

To limit the coolant input capability, the LCO requires that no HHSI pumps be capable of injecting into the RCS and all accumulator discharge isolation valves closed and de-energized if accumulator pressure is greater than or equal to the maximum RCS pressure for the existing RCS cold leg temperature allowed in the PTLR.

The elements of the LCO that provide low temperature overpressure mitigation through pressure relief are:

a. Two OPERABLE PORVs configured as part of an OPERABLE Overpressure Protection System (OPS); or

b. A depressurized RCS and an RCS vent.

A PORV is OPERABLE for LTOP when its block valve is open, its lift setpoint is set to the limit required by the PTLR and testing proves its ability to open at this setpoint, and motive power is available to the two valves and their control circuits. The OPS is OPERABLE for LTOP when there are three OPERABLE RCS pressure channels and three OPERABLE RCS temperature channels. The OPS is still OPERABLE when an inoperable RCS pressure or temperature channel is in the tripped condition.

An RCS vent is OPERABLE when open with an area of ≥ 2.00 square inches.

Each of these methods of overpressure prevention is capable of mitigating the limiting LTOP transient.

APPLICABILITY

This LCO is applicable whenever the RHR System is not isolated from the RCS to protect the RHR system piping. When average RCS cold leg temperatures are ≥ 319°F, RHR system piping is adequately protected by making the accumulators and all HHSI

BASES

APPLICABILITY (continued)

pumps incapable of injecting into the RCS. Therefore, a Note in the LCO specifies that requirements for the OPS System and/or an RCS vent are not Applicable when average RCS cold leg temperature is ≥ 319°F.

This LCO is applicable to provide protection for the RCS pressure boundary in MODE 4 when average RCS cold leg temperature is < 319°F, in MODE 5, and in MODE 6 when the reactor vessel head is on. The pressurizer safety valves provide overpressure protection that meets the Reference 1 P/T limits above 319°F. When the reactor vessel head is off, overpressurization cannot occur. Although LTOP is not Applicable when the RCS temperature is greater than the LTOP arming temperature (i.e., ≥ 319°F) but below the minimum temperature at which the pressurizer safety valves lift prior to violation of the 10 CFR 50, Appendix G, limits (i.e., ≤ 411°F), administrative controls in the Technical Requirements Manual (TRM) (Ref. 4) are used to limit the potential for exceeding 10 CFR 50, Appendix G, limits.

LCO 3.4.3 provides the operational P/T limits for all MODES. LCO 3.4.10, "Pressurizer Safety Valves," requires the OPERABILITY of the pressurizer safety valves that provide overpressure protection during MODES 1, 2, and 3, and MODE 4 above 319°F.

Low temperature overpressure prevention is most critical during shutdown when the RCS is water solid, and a mass or heat input transient can cause a very rapid increase in RCS pressure when little or no time allows operator action to mitigate the event.

The Applicability is modified by three Notes, Note 1 states that accumulator isolation is only required when the accumulator pressure is more than the maximum RCS pressure for the existing temperature, as allowed by the P/T limit curves. This Note permits the accumulator discharge isolation valve Surveillance to be performed only under these pressure and temperature conditions.

Note 2 ensures that LCO 3.4.12 will not prohibit a HHSI pump being energized and aligned to the RCS as needed to support emergency boration or to respond to a loss of RHR cooling.

BASES

APPLICABILITY (continued)

Note 3 specifies that one HHSI pump may be made capable of injecting into the RCS for a period not to exceed 8 hours to perform pump testing. During testing, administrative controls are used to ensure that HHSI testing will not result in exceeding RCS or RHR system pressure limits. It is preferred that HHSI pump testing is performed when average RCS cold leg temperature is ≤ 200°F because either one PORV or an RCS vent of ≥ 2.00 square inches is capable of accommodating an injection from one HHSI pump without exceeding LTOP limits for the RCS boundary. However, until the RCS temperature is ≤ 200°F, an RCS vent cannot be established and the PORV will not protect the RHR system because the temperature dependent OPS lift setpoint will be greater than the design pressure of the RHR system.

ACTIONS

A.1, A.2.1, A.2.2, A.2.3, A.3.1 and A.3.2

When one or more HHSI pumps are capable of injecting into the RCS, LTOP assumptions regarding limits on mass input capability may not be met. Therefore, immediate action is required to limit injection capability consistent with the LTOP analysis assumptions and the existing combination of pressurizer level and RCS venting capacity. Required Action A.1 requires restoration with LCO requirements. Required Actions A.2 and A.3 require verification and periodic re-verification that alternate LTOP configurations are met. The Completion Times of immediately reflects the urgency that one of the acceptable LTOP configurations is established as soon as possible.

B.1, C.1 and C.2

To be considered isolated, an accumulator must have its discharge valves closed and the valve power supply breakers fixed in the open position.

An unisolated accumulator requires isolation within 1 hour. This is only required when the accumulator pressure is at or more than the maximum RCS pressure for the existing temperature allowed by the P/T limit curves.

BASES

ACTIONS

B.1, C.1 and C.2 (continued)

If isolation is needed and cannot be accomplished in 1 hour, Required Action C.1 and Required Action C.2 provide two options, either of which must be performed in the next 12 hours. By increasing the RCS temperature to ≥ 319°F, an accumulator pressure of 700 psig cannot exceed the LTOP limits if the accumulators are injected. Depressurizing the accumulators below the LTOP limit from the PTLR also gives this protection. Additionally, the RHR System must be isolated from the RCS to protect RHR piping from a potential mass addition event.

The Completion Times are based on operating experience that these activities can be accomplished in these time periods and on engineering evaluations indicating that an event requiring LTOP is not likely in the allowed times.

D.1

When average RCS cold leg temperature is < 319°F, with one required PORV inoperable, the PORV must be restored to OPERABLE status within a Completion Time of 7 days. Two PORVs are required to provide low temperature overpressure mitigation while withstanding a single failure of an active component.

The Completion Time considers the facts that only one of the PORVs is required to mitigate an overpressure transient and that the likelihood of an active failure of the remaining valve path during this time period is very low.

E.1

When both required PORVs are inoperable or the Required Action and associated Completion Time of Condition C or D is not met, an alternate method of low temperature overpressure protection must be established within 8 hours. The acceptable alternate methods of LTOP include the following:

a. Depressurize the RCS and establish an RCS vent path; or

b. Increase average RCS cold leg temperatures to ≥ 319°F; or

BASES

ACTIONS

E.1 (continued)

c. Establish a combination of pressurizer level, RCS pressure, and RCS injection capability within limits specified in PTLR for OPS not OPERABLE. This combination will ensure at least 10 minutes for operator intervention to prevent overpressurization following a transient.

If the option selected is to depressurize the RCS and establish an RCS vent path, the vent must be sized ≥ 2.00 square inches to ensure that the flow capacity is greater than that required for the worst case mass input transient reasonable during the applicable MODES. This action is needed to protect the RCPB from a low temperature overpressure event and a possible brittle failure of the reactor vessel.

The Completion Time considers the time required to place the plant in this Condition and the relatively low probability of an overpressure event during this time period due to increased operator awareness of administrative control requirements.

F.1

If LTOP requirements are not met for reasons other than Conditions A, B, C, D or E, LTOP requirements must be re-established by depressurizing the RCS and establishing an RCS vent of ≥ 2.00 square inches within 8 hours.

SURVEILLANCE REQUIREMENTS

SR 3.4.12.1 and SR 3.4.12.2

To minimize the potential for a low temperature overpressure event by limiting the mass input capability, all HHSI pumps are verified incapable of injecting into the RCS. Additionally, the accumulator discharge isolation valves are verified closed and locked out or the accumulator pressure less than the maximum RCS pressure for the existing RCS cold leg temperature allowed by the P/T limit curves provided in the PTLR.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.12.1 and SR 3.4.12.2 (continued)

The HHSI pumps are rendered incapable of injecting into the RCS through removing the power from the pumps by racking the breakers out under administrative control. Other methods may be employed using at least two independent means to prevent a pump start such that a single failure or single action will not result in an injection into the RCS. This may be accomplished through the pump control switch being placed in Trip Pullout and at least one valve in the discharge flow path being closed.

The Frequency of 12 hours is sufficient, considering other indications and alarms available to the operator in the control room, to verify the required status of the equipment.

SR 3.4.12.3

The RCS vent of ≥ 2.00 square inches is proven OPERABLE by verifying its open condition either:

a. Once every 12 hours for a valve that is not locked.

b. Once every 31 days for a valve that is locked, sealed, or secured in position. A removed pressurizer safety valve, PORV, or Manway Cover fits this category.

The passive vent arrangement must only be open to be OPERABLE. This Surveillance is required to be performed if the vent is being used to satisfy the pressure relief requirements of the LCO 3.4.12.b.

SR 3.4.12.4

Performance of the CHANNEL CHECK of the Overpressure Protection System (OPS) RCS pressure and temperature channels every 24 hours ensures that gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.12.4 (continued)

monitoring the same parameter should read approximately the same value. Significant deviations between the two instrument channels could be an indication of excessive instrument drift in one of the channels or of something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying that the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

Agreement criteria are determined by the unit staff based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the sensor or the signal processing equipment has drifted outside its limit.

The Frequency is based on operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the LCO required channels. This SR is required only when LCO 3.4.12.a is used to establish LTOP protection.

SR 3.4.12.5

The PORV block valve opens automatically when RCS cold leg temperature is below the OPS arming temperature; however, the valves must be verified open every 72 hours to provide the flow path for each required PORV to perform its function when actuated. The valve may be remotely verified open in the control room. This Surveillance is performed only if the PORV is being used to satisfy LCO 3.4.12.a.

The block valve is a remotely controlled, motor operated valve. The power to the valve operator is not required removed, and the manual operator is not required locked in the inactive position. Thus, the block valve can be closed in the event the PORV develops excessive leakage or does not close (sticks open) after relieving an overpressure situation. If closed, the block valve

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.12.5 (contdinued)

must be de-energized to prevent the valve from re-opening automatically.

The 72 hour Frequency is considered adequate because the PORV block valves are opened automatically by the OPS when below the OPS arming temperature if the valve control is positioned to auto and other administrative controls available to the operator in the control room, such as valve position indication, that verify that the PORV block valve remains open.

SR 3.4.12.6

Performance of a COT is required within 12 hours after decreasing RCS temperature to < 319°F and every 31 days on each required PORV to verify and, as necessary, adjust its lift setpoint. The COT will verify the setpoint is within the PTLR allowed maximum limits in the PTLR. PORV actuation could depressurize the RCS and is not required.

The 31 day Frequency considers the demonstrated reliability of the Overpressure Protection System and the PORVs.

A Note has been added indicating that this SR is required to be met 12 hours after decreasing RCS cold leg temperature to < 319 °F. The COT cannot be performed until in the LTOP MODES when the PORV lift setpoint can be reduced to the LTOP setting. The test must be performed within 12 hours after entering the LTOP MODES.

SR 3.4.12.7

Performance of a CHANNEL CALIBRATION on each required PORV actuation channel is required every 18 months. Performance of a CHANNEL CALIBRATION of RCS pressure and temperature instruments that support the Overpressure Protection System is required every 24 months. These calibrations verify both the OPS and PORV function and ensure the OPERABILITY of the whole channel so that

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.12.7 (continued)

it responds and the valve opens within the required range and accuracy to known input.

SR 3.4.12.8 and SR 3.4.12.9

The RCP starting prerequisites must be satisfied prior to starting or jogging any reactor coolant pump (RCP) when low temperature overpressure protection is required. The RCP starting prerequisites prevent an overpressure event due to thermal transients when an RCP is started. Plant conditions prior to the RCP start determines whether SR 3.4.12.8 or SR 3.4.12.9 must be satisfied prior to starting any RCP.

The principal contributor to an RCP start induced thermal and pressure transient is the difference between RCS cold leg temperatures and secondary side water temperature of any SG prior to the start of an RCP. The RCP starting prerequisites vary depending on plant conditions but include the following: reactor coolant temperature relative to the LTOP enable temperature; secondary side water temperature of the hottest SG relative to the temperature of the coldest RCS cold leg temperature; and, status of the Overpressure Protection System (OPS). When the OPS is inoperable, additional compensatory requirements are required including limits for the pressurizer level and RCS pressure and temperature. When a pressurizer level is specified as a requirement, the level specified is sufficient to prevent the RCS from going water solid for 10 minutes which is sufficient time for operator action to terminate the pressure transient.

SR 3.4.12.8 is used if secondary side water temperature of the hottest steam generator (SG) is less than or equal to the coldest RCS cold leg temperature. SR 3.4.12.9 is more restrictive and is used if the secondary side water temperature of the hottest steam generator is ≤ 64°F above the coldest RCS cold leg temperature.

RCP starting is prohibited if the hottest steam generator is > 64°F above RCS cold leg temperature or if neither of the RCP starting prerequisites SRs can be satisfied.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.12.8 and SR 3.4.12.9 (continued)

The steam generator temperature may be measured using the Control Room instrumentation or, as a backup, from a contact reading off the steam generator's shells. Pressurizer level may be determined using control room instrumentation or alternate methods.

The FREQUENCY of the RCP starting prerequisites SRs is Within 15 minutes prior to starting any RCP. This means that each of the required verifications must be performed within 15 minutes prior to the pump start and must be met at the time of the pump start.

SR 3.4.12.8 and SR 3.4.12.9 are each modified by two Notes. Note 1 specifies that these SRs are required as a condition for pump starting only when the RCS is below the LTOP arming temperature. Note 2 specifies that meeting either SR 3.4.12.8 or SR 3.4.12.9 ensures that pump starting prerequisites are met.

BASES

REFERENCES

1. 10 CFR 50, Appendix G.

2. Generic Letter 88-011, NRC Position on Radiation Embrittlement of Reactor Vessel Materials and its Impact on Plant Operations.

3. IP3 Low Temperature Overpressurization System Analysis Final Report, August 24, 1984, in conjunction with ASME Code Case N-514, Low Temperature Overpressure Protection, February 12, 1992.

4. IP3 Technical Requirements Manual.

5. 10 CFR 50, Section 50.46.

6. 10 CFR 50, Appendix K.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.13 RCS Operational LEAKAGE

BASES

BACKGROUND

Components that contain or transport the coolant to or from the reactor core make up the RCS. Component joints are made by welding, bolting, rolling, or pressure loading, and valves isolate connecting systems from the RCS.

During plant life, the joint and valve interfaces can produce varying amounts of reactor coolant LEAKAGE, through either normal operational wear or mechanical deterioration. The purpose of the RCS Operational LEAKAGE LCO is to limit system operation in the presence of LEAKAGE from these sources to amounts that do not compromise safety. This LCO specifies the types and amounts of LEAKAGE. 10 CFR 50, Appendix A, GDC 30 (Ref. 1), requires means for detecting and, to the extent practical, identifying the source of reactor coolant LEAKAGE.

The safety significance of RCS LEAKAGE varies widely depending on its source, rate, and duration. Therefore, detecting and monitoring reactor coolant LEAKAGE into the containment area is necessary. Quickly separating the identified LEAKAGE from the unidentified LEAKAGE is necessary to provide quantitative information to the operators, allowing them to take corrective action should a leak occur that is detrimental to the safety of the facility and the public.

A limited amount of leakage inside containment is expected from auxiliary systems that cannot be made 100% leaktight. Leakage from these systems should be detected, located, and isolated from the containment atmosphere, if possible, to not interfere with RCS leakage detection.

This LCO deals with protection of the reactor coolant pressure boundary (RCPB) from degradation and the core from inadequate cooling, in addition to preventing the accident analyses radiation release assumptions from being exceeded. The consequences of violating this LCO include the possibility of a loss of coolant accident (LOCA).

BASES

APPLICABLE SAFETY ANALYSES

Except for primary to secondary LEAKAGE, the safety analyses do not address operational LEAKAGE. However, other operational LEAKAGE is related to the safety analyses for LOCA; the amount of leakage can affect the probability of such an event. The safety analysis for events resulting in steam discharge to the atmosphere assumes a range of primary to secondary LEAKAGE from 0.1 gpm to 10 gpm as the initial condition.

Primary to secondary LEAKAGE is a factor in the dose releases outside containment resulting from a steam line break (SLB) accident. To a lesser extent, other accidents or transients involve secondary steam release to the atmosphere, such as a steam generator tube rupture (SGTR). The leakage contaminates the secondary fluid.

The FSAR (Ref. 2) analysis for SGTR assumes the contaminated secondary fluid is released via safety valves and atmospheric dump valves. The 1 gpm primary to secondary LEAKAGE is relatively inconsequential.

The SLB is more limiting for site radiation releases. The safety analysis for the SLB accident assumes a range of primary to secondary LEAKAGE as an initial condition. The dose consequences resulting from the SLB accident are well within the limits defined in 10 CFR 100 and the staff approved licensing basis (i.e., a small fraction of these limits).

The RCS operational LEAKAGE satisfies Criterion 2 of 10 CFR 50.36.

LCO

RCS operational LEAKAGE shall be limited to:

a. <u>Pressure Boundary LEAKAGE</u>

No pressure boundary LEAKAGE is allowed, being indicative of material deterioration. LEAKAGE of this type is unacceptable as the leak itself could cause further deterioration, resulting in higher LEAKAGE. Violation of

BASES

LCO

a. (continued)

this LCO could result in continued degradation of the RCPB. LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE.

b. Unidentified LEAKAGE

One gallon per minute (gpm) of unidentified LEAKAGE is allowed as a reasonable minimum detectable amount and is consistent with the capability of the equipment required by LCO 3.4.15, RCS Leakage Detection Instrumentation. Violation of this LCO could result in continued degradation of the RCPB, if the LEAKAGE is from the pressure boundary.

c. Identified LEAKAGE

Up to 10 gpm of identified LEAKAGE is considered allowable because LEAKAGE is from known sources that do not interfere with detection of unidentified LEAKAGE and is well within the capability of the RCS Makeup System. Identified LEAKAGE includes LEAKAGE to the containment from specifically known and located sources, but does not include pressure boundary LEAKAGE, the leakage into closed systems or controlled reactor coolant pump (RCP) seal leakoff (a normal function not considered LEAKAGE). Violation of this LCO could result in continued degradation of a component or system.

d. Primary to Secondary LEAKAGE through All Steam Generators (SGs)

Total primary to secondary LEAKAGE amounting to 1 gpm (1440 gpd) through all SGs produces acceptable offsite doses in the SLB accident analysis. Violation of this LCO could exceed the offsite dose limits for this accident. Primary to secondary LEAKAGE must be included in the total allowable limit for identified LEAKAGE.

BASES

LCO (continued)

e. Primary to Secondary LEAKAGE through Any One SG

The 432 gallons per day (0.3 gpm) limit on one SG is based on the assumption that a single crack leaking this amount would not propagate to a SGTR under the stress conditions of a LOCA or a main steam line rupture. If leaked through many cracks, the cracks are very small, and the above assumption is conservative.

APPLICABILITY

In MODES 1, 2, 3, and 4, the potential for RCPB LEAKAGE is greatest when the RCS is pressurized.

In MODES 5 and 6, LEAKAGE limits are not required because the reactor coolant pressure is far lower, resulting in lower stresses and reduced potentials for LEAKAGE.

Leakage past PIVs or other leakage into closed systems is that leakage that can be accounted for and contained by a system not directly connected to the atmosphere. Leakage past PIVs or other leakage into closed systems is not included in the limits for either identified or unidentified LEAKAGE but PIV leakage must be within the limits specified for PIVs in LCO 3.4.14, "RCS Pressure Isolation Valves (PIV)." Leakage past PIVs or other leakage into closed systems is quantified before being exempted from the limits for identified LEAKAGE.

ACTIONS

A.1

Unidentified LEAKAGE, identified LEAKAGE, or primary to secondary LEAKAGE in excess of the LCO limits must be reduced to within limits within 4 hours. This Completion Time allows time to verify leakage rates and either identify unidentified LEAKAGE or reduce LEAKAGE to within limits before the reactor must be shut down. This action is necessary to prevent further deterioration of the RCPB.

BASES

ACTIONS (continued)

B.1 and B.2

If any pressure boundary LEAKAGE exists, or if unidentified LEAKAGE, identified LEAKAGE, or primary to secondary LEAKAGE cannot be reduced to within limits within 4 hours, the reactor must be brought to lower pressure conditions to reduce the severity of the LEAKAGE and its potential consequences. It should be noted that LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE. The reactor must be brought to MODE 3 within 6 hours and MODE 5 within 36 hours. This action reduces the LEAKAGE and also reduces the factors that tend to degrade the pressure boundary.

The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems. In MODE 5, the pressure stresses acting on the RCPB are much lower, and further deterioration is much less likely.

SURVEILLANCE REQUIREMENTS

SR 3.4.13.1

Verifying RCS LEAKAGE to be within the LCO limits ensures the integrity of the RCPB is maintained. Pressure boundary LEAKAGE would at first appear as unidentified LEAKAGE and can only be positively identified by inspection. It should be noted that LEAKAGE past seals and gaskets is not pressure boundary LEAKAGE. Unidentified LEAKAGE and identified LEAKAGE are determined by performance of an RCS water inventory balance. Primary to secondary LEAKAGE is also measured by performance of an RCS water inventory balance in conjunction with effluent monitoring within the secondary steam and blowdown systems.

The RCS water inventory balance must be met with the reactor at steady state operating conditions and near operating pressure. Therefore, this SR is not required to be performed in MODES 3

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.13.1 (continued)

and 4 until 12 hours of steady state operation near operating pressure have been established.

Steady state operation is required to perform a proper inventory balance; calculations during maneuvering are not useful and a Note requires the Surveillance to be met when steady state is established. For RCS operational LEAKAGE determination by water inventory balance, steady state is defined as stable RCS pressure, temperature, power level, pressurizer and makeup tank levels, makeup and letdown, and RCP seal injection and return flows.

An early warning of pressure boundary LEAKAGE or unidentified LEAKAGE is provided by the automatic systems that monitor the containment atmosphere radioactivity and the containment sump level. These leakage detection systems are specified in LCO 3.4.15, "RCS Leakage Detection Instrumentation." It should be noted that LEAKAGE past seals and gaskets, measured leakage past PIVs, and other leakage into closed systems is not pressure boundary LEAKAGE.

The 72 hour Frequency is a reasonable interval to trend LEAKAGE and recognizes the importance of early leakage detection in the prevention of accidents. A Note under the Frequency column states that this SR is required to be performed during steady state operation.

SR 3.4.13.2

This SR provides the means necessary to determine SG OPERABILITY in an operational MODE. The requirement to demonstrate SG tube integrity in accordance with the Steam Generator Tube Surveillance Program emphasizes the importance of SG tube integrity, even though this Surveillance cannot be performed at normal operating conditions.

BASES

REFERENCES

1. 10 CFR 50, Appendix A, GDC 30.
2. FSAR, Section 14.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.14 RCS Pressure Isolation Valve (PIV) Leakage

BASES

BACKGROUND

10 CFR 50.2, 10 CFR 50.55a(c), and GDC 55 of 10 CFR 50, Appendix A (Refs. 1, 2, and 3), define RCS PIVs as any two normally closed valves in series within the reactor coolant pressure boundary (RCPB), which separate the high pressure RCS from an attached low pressure system. During their lives, these valves can produce varying amounts of reactor coolant leakage through either normal operational wear or mechanical deterioration. The RCS PIV Leakage LCO allows RCS high pressure operation when leakage through these valves exists in amounts that do not compromise safety. This LCO establishes limits for Event V PIVs only. Event V PIVs are defined as two check valves in series at a low pressure/RCS interface whose failure may result in a LOCA that by-passes containment. Event V refers to the scenario described for this event in the WASH-1400 study (Refs. 4 and 9). The Event V PIVs are listed in FSAR, Section 6 (Ref. 6).

The PIV leakage limit applies to each individual valve. Leakage through PIVs into closed systems is not included in the limits for either identified or unidentified LEAKAGE in LCO 3.4.13, RCS Operational LEAKAGE. Leakage past PIVs into closed systems is that leakage which can be accounted for and contained by a system not directly connected to the atmosphere.

Although this specification provides a limit on allowable PIV leakage rate, its main purpose is to prevent overpressure failure of the low pressure portions of connecting systems. The leakage limit is an indication that the PIVs between the RCS and the connecting systems are degraded or degrading. PIV leakage could lead to overpressure of the low pressure piping or components. Failure consequences could be a loss of coolant accident (LOCA) outside of containment, an unanalyzed accident, that could degrade the ability for low pressure injection.

The basis for this LCO is the 1975 NRC "Reactor Safety Study" (Ref. 4) that identified potential intersystem LOCAs as a

BASES

BACKGROUND (Continued)

significant contributor to the risk of core melt. A subsequent study (Ref. 5) evaluated various PIV configurations to determine the probability of intersystem LOCAs.

PIVs are typically provided to isolate the RCS from the following connected systems:

a. Residual Heat Removal (RHR) System; and

b. Safety Injection System.

Violation of this LCO could result in continued degradation of a PIV, which could lead to overpressurization of a low pressure system and the loss of the integrity of a fission product barrier.

Residual Heat Removal System Valves 730 and 731 isolate the RHR System from the RCS and are separately interlocked with independent pressure control signals to prevent their being opened whenever the RCS pressure is greater than a designated setpoint (which is below the RHR System design pressure of 600 psig). This interlock also automatically closes the valve whenever the Reactor Coolant System pressure increases to a slightly higher setpoint. This interlock provides a diverse backup to administrative requirements to close the isolation valves when needed to prevent RHR system overpressurization. In addition to this interlock, the valve motor operators are mechanically sized such that there is insufficient torque to open the valve in the presence of a pressure differential greater than the RHR System design pressure. Finally, the RHR System is equipped with a pressure relief valve sized to relieve the flow of two charging pumps. Collectively, these features provide a diverse backup to administrative requirements to close the isolation valves when needed to prevent RHR system overpressurization.

BASES

APPLICABLE SAFETY ANALYSES

Reference 4 identified potential intersystem LOCAs as a significant contributor to the risk of core melt. The dominant accident sequence in the intersystem LOCA category is the failure of the low pressure portion of the RHR System outside of containment.

The accident is the result of a postulated failure of the PIVs, which are part of the RCPB, and the subsequent pressurization of the RHR System downstream of the PIVs from the RCS. Because the low pressure portion of the RHR System is designed for 600 psig, overpressurization failure of the RHR low pressure line would result in a LOCA outside containment and subsequent risk of core melt.

Reference 5 evaluated various PIV configurations, leakage testing of the valves, and operational changes to determine the effect on the probability of intersystem LOCAs. This study concluded that periodic leakage testing of the PIVs can substantially reduce the probability of an intersystem LOCA.

The RHR isolation valve autoclosure and interlock provides a diverse backup to administrative requirements to close the isolation valves when needed to prevent RHR system overpressurization.

RCS PIV leakage satisfies Criterion 2 of 10 CFR 50.36.

LCO

This LCO establishes limits for Event V PIVs only. Event V PIVs are defined as two check valves in series at a low pressure/RCS interface whose failure may result in a LOCA that by-passes containment. Event V refers to the scenario described for this event in the WASH-1400 study (Refs. 4 and 9). The Event V PIVs are listed in FSAR, Section 6 (Ref. 6).

RCS PIV leakage is leakage into closed systems connected to the RCS. Leakage through PIVs into closed systems is not included in the limits for either identified or unidentified LEAKAGE in LCO

BASES

LCO (continued)

3.4.13, RCS Operational LEAKAGE. Leakage past PIVs into closed systems is that leakage which can be accounted for and contained by a system not directly connected to the atmosphere. Isolation valve leakage is usually on the order of drops per minute. Leakage that increases significantly suggests that something is operationally wrong and corrective action must be taken.

The LCO PIV leakage limit is 0.5 gpm per nominal inch of valve size with a maximum limit of 5 gpm. The previous criterion of 1 gpm for all valve sizes imposed an unjustified penalty on the larger valves without providing information on potential valve degradation and resulted in higher personnel radiation exposures. A study concluded a leakage rate limit based on valve size was superior to a single allowable value.

Reference 7 permits leakage testing at a lower pressure differential than between the specified maximum RCS pressure and the normal pressure of the connected system during RCS operation (the maximum pressure differential) in those types of valves in which the higher service pressure will tend to diminish the overall leakage channel opening. In such cases, the observed rate may be adjusted to the maximum pressure differential by assuming leakage is directly proportional to the pressure differential to the one half power.

The autoclosure interlock for RHR System Valves 730 and 731 must function to automatically close or prevent the opening of the RHR isolation valves whenever the RCS pressure is greater than the RHR System design pressure. The autoclosure interlock is considered OPERABLE when the isolation valves are closed and the motor operators de-energized if the interlock would function when power is restored to the motor operator.

APPLICABILITY

In MODES 1, 2, 3, and 4, this LCO applies because the PIV leakage potential is greatest when the RCS is pressurized. In MODE 4, valves in the RHR flow path are not required to meet the requirements of this LCO when in, or during the transition to or from, the RHR mode of operation.

BASES

APPLICABILITY (continued)

In MODES 5 and 6, leakage limits and RHR autoclosure function are not provided because the lower reactor coolant pressure results in a reduced potential for leakage and for a LOCA outside the containment.

ACTIONS

The Actions are modified by two Notes. Note 1 provides clarification that each flow path allows separate entry into a Condition. This is allowed based upon the functional independence of the flow path. Note 2 requires an evaluation of affected systems if a PIV is inoperable. The leakage may have affected system operability, or isolation of a leaking flow path with an alternate valve may have degraded the ability of the interconnected system to perform its safety function.

A.1 and A.2

The flow path must be isolated by two valves. Required Actions A.1 and A.2 are modified by a Note that the valves used for isolation must meet the same leakage requirements as the PIVs and must be within the RCPB or the high pressure portion of the system.

Required Action A.1 requires that the isolation with one valve must be performed within 4 hours. Four hours provides time to reduce leakage in excess of the allowable limit and to isolate the affected system if leakage cannot be reduced. The 4 hour Completion Time allows the actions and restricts the operation with leaking isolation valves.

Required Action A.2 specifies that the double isolation barrier of two valves be restored by closing some other valve qualified for isolation or restoring one leaking PIV. The 72 hour Completion Time after exceeding the limit considers the time required to complete the Action and the low probability of a second valve failing during this time period. If use of a closed

BASES

ACTIONS

A.1 and A.2 (continued)

manual, deactivated automatic, or check valve to isolate leaking PIV renders a required system or component inoperable, then the Required Actions associated with the affected system or component are initiated when the valve is closed.

B.1 and B.2

If leakage cannot be reduced, the system isolated, or the other Required Actions accomplished, the plant must be brought to a MODE in which the requirement does not apply. To achieve this status, the plant must be brought to MODE 3 within 6 hours and MODE 5 within 36 hours. This Action may reduce the leakage and also reduces the potential for a LOCA outside the containment. The allowed Completion Times are reasonable based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

C.1

The inoperability of the RHR autoclosure interlock renders the RHR suction isolation valves incapable of isolating in response to a high pressure condition and preventing inadvertent opening of the valves at RCS pressures in excess of the RHR systems design pressure. If the RHR autoclosure interlock is inoperable, operation may continue as long as the affected RHR suction penetration is closed by at least one closed manual or deactivated automatic valve within 4 hours. This Action accomplishes the purpose of the autoclosure function.

A Note to Required Action C.1 specifies that the RHR system flowpath may be unisolated under administrative controls if needed to meet requirements for an operating RCS loop in LCO 3.4.5, RCS Loops - MODE 3, and LCO 3.4.6, RCS Loops - MODE 4. Additionally, an RHR loop may be considered OPERABLE but not in operation with one or both RHR isolation valves closed and deactivated if the valves can be opened as allowed by this Note in a reasonable time. This Note is needed because neither of the two RHR loops can be in operation when either RHR valve 730 or 731 is closed.

BASES

ACTIONS

C.1 (continued)

This allowance is acceptable because the interlock is intended to provide a diverse backup to administrative requirements to close the isolation valves when needed to prevent RHR system overpressurization. In addition to this interlock, the valve motor operators are mechanically sized such that there is insufficient torque to open the valve in the presence of a pressure differential greater than the RHR System design pressure and the RHR System is equipped with a pressure relief valve sized to relieve the flow of three charging pumps.

SURVEILLANCE REQUIREMENTS

SR 3.4.14.1

Performance of leakage testing on each RCS PIV or isolation valve used to satisfy Required Action A.1 and Required Action A.2 is required to verify that leakage is below the specified limit and to identify each leaking valve. The leakage limit of 0.5 gpm per inch of nominal valve diameter up to 5 gpm maximum applies to each valve. Leakage testing requires a stable pressure condition.

For the two PIVs in series, the leakage requirement applies to each valve individually and not to the combined leakage across both valves. If the PIVs are not individually leakage tested, one valve may have failed completely and not be detected if the other valve in series meets the leakage requirement. In this situation, the protection provided by redundant valves would be lost.

Testing is to be performed every 24 months, a typical refueling cycle, if the plant does not go into MODE 5 for at least 7 days. The 24 month Frequency is consistent with 10 CFR 50.55a(g) (Ref. 8) as contained in the Inservice Testing Program, is within frequency allowed by the American Society of Mechanical Engineers (ASME) Code, Section XI (Ref. 7), and is based on the need to perform such surveillances under the conditions that apply during

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.14.1 (continued)

an outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power.

In addition, testing must be performed once after the valve has been opened by flow or exercised to ensure tight reseating. PIVs disturbed in the performance of this Surveillance should also be tested unless documentation shows that an infinite testing loop cannot practically be avoided. Testing must be performed within 24 hours after the valve has been reseated. Within 24 hours is a reasonable and practical time limit for performing this test after opening or reseating a valve.

The leakage limit is to be met at the RCS pressure associated with MODES 1 and 2. This permits leakage testing at high differential pressures with stable conditions not possible in the MODES with lower pressures.

Entry into MODES 3 and 4 is allowed to establish the necessary differential pressures and stable conditions to allow for performance of this Surveillance. The Note that allows this provision is complementary to the Frequency of prior to entry into MODE 2 whenever the unit has been in MODE 5 for 7 days or more, if leakage testing has not been performed in the previous 12 months. In addition, this Surveillance is not required to be performed on the RHR System when the RHR System is aligned to the RCS in the shutdown cooling mode of operation. PIVs contained in the RHR shutdown cooling flow path must be leakage rate tested after RHR is secured and stable unit conditions and the necessary differential pressures are established.

SR 3.4.14.2 and SR 3.4.14.3

Verifying that the RHR autoclosure interlocks are OPERABLE ensures that RCS pressure will not pressurize the RHR system beyond 125% of its design pressure of 600 psig. The interlock setpoint that prevents the valves from being opened is set so the actual RCS pressure must be < 450 psig to open the valves. This setpoint ensures the RHR design pressure will not be exceeded and

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.14.2 and SR 3.4.14.3 (continued)

the RHR relief valves will not lift. The 24 month Frequency is based on the need to perform the Surveillance under conditions that apply during a plant outage. The 24 month Frequency is also acceptable based on consideration of the design reliability (and confirming operating experience) of the equipment.

REFERENCES

1. 10 CFR 50.2.
2. 10 CFR 50.55a(c).
3. 10 CFR 50, Appendix A.
4. WASH-1400 (NUREG-75/014), Appendix V, October 1975.
5. NUREG-0677, May 1980.
6. FSAR Section 6.2.
7. ASME, Boiler and Pressure Vessel Code, Section XI.
8. 10 CFR 50.55a(g).
9. Generic Letter 87-006, Periodic Verification of Leak Tight Integrity of Pressure Isolation Valves.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.15 RCS Leakage Detection Instrumentation

BASES

BACKGROUND

GDC 30 of Appendix A to 10 CFR 50 (Ref. 1) requires means for detecting and, to the extent practical, identifying the location of the source of RCS LEAKAGE.

Leakage detection systems must have the capability to detect significant reactor coolant pressure boundary (RCPB) degradation as soon after occurrence as practical to minimize the potential for propagation to a gross failure. Thus, an early indication or warning signal is necessary to permit proper evaluation of all unidentified LEAKAGE.

Industry practice has shown that water flow changes of 0.5 to 1.0 gpm can be readily detected in contained volumes by monitoring changes in water level, in flow rate, or in the operating frequency of a pump. The containment sump used to collect unidentified LEAKAGE and containment fan cooler unit condensate measuring system are instrumented to alarm for increases of 0.5 to 1.0 gpm. This sensitivity is acceptable for detecting increases in unidentified LEAKAGE.

The reactor coolant contains radioactivity that, when released to the containment, can be detected by radiation monitoring instrumentation. Reactor coolant radioactivity levels will be low during initial reactor startup and for a few weeks thereafter, until activated corrosion products have been formed and fission products appear from fuel element cladding contamination or cladding defects. Instrument sensitivities of 10^{-11} μCi/cc radioactivity for particulate monitoring and of 10^{-7} μCi/cc radioactivity for gaseous monitoring are practical for these leakage detection systems. Radioactivity detection systems are included for monitoring both particulate (R-11) and gaseous activities (R-12) because of their sensitivities and rapid responses to RCS LEAKAGE.

An increase in humidity of the containment atmosphere would indicate release of water vapor to the containment. Dew point temperature measurements can thus be used to monitor humidity

BASES

BACKGROUND (Continued)

levels of the containment atmosphere as an indicator of potential RCS LEAKAGE. A 1°F increase in dew point is well within the sensitivity range of available instruments.

Since the humidity level is influenced by several factors, a quantitative evaluation of an indicated leakage rate by this means may be questionable and should be compared to observed increases in liquid flow into or from the containment sump and condensate flow from fan cooler unit condensate measuring system. Humidity level monitoring is considered most useful as an indirect alarm or indication to alert the operator to a potential problem. Humidity monitors are not required by this LCO.

Air temperature and pressure monitoring methods may also be used to infer unidentified LEAKAGE to the containment. Containment temperature and pressure fluctuate slightly during plant operation, but a rise above the normally indicated range of values may indicate RCS leakage into the containment. The relevance of temperature and pressure measurements are affected by containment free volume and, for temperature, detector location. Alarm signals from these instruments can be valuable in recognizing rapid and sizable leakage to the containment. Temperature and pressure monitors are not required by this LCO.

APPLICABLE SAFETY ANALYSES

The need to evaluate the severity of an alarm or an indication is important to the operators, and the ability to compare and verify with indications from other systems is necessary. The system response times and sensitivities are described in the FSAR (Ref. 2).

The safety significance of RCS LEAKAGE varies widely depending on its source, rate, and duration. Therefore, detecting and monitoring RCS LEAKAGE into the containment area is necessary. Quickly separating the identified LEAKAGE from the unidentified LEAKAGE provides quantitative information to the operators, allowing them to take corrective action should a leakage occur detrimental to the safety of the unit and the public.

BASES

APPLICABLE SAFETY ANALYSES (continued)

RCS leakage detection instrumentation satisfies Criterion 1 of 10 CFR 50.36.

LCO

One method of protecting against large RCS leakage derives from the ability of instruments to rapidly detect extremely small leaks. This LCO requires instruments of diverse monitoring principles to be OPERABLE to provide a high degree of confidence that extremely small leaks are detected in time to allow actions to place the plant in a safe condition, when RCS LEAKAGE indicates possible RCPB degradation.

The LCO is satisfied when monitors of diverse measurement means are available. Thus, the containment sump flow monitor, in combination with a gaseous or particulate radioactivity monitor and a containment fan cooler unit condensate measuring system, provides an acceptable minimum. The condensate measuring system associated with any one of the fan cooler unit satisfies the requirement for a fan cooler unit condensate measuring system.

APPLICABILITY

Because of elevated RCS temperature and pressure in MODES 1, 2, 3, and 4, RCS leakage detection instrumentation is required to be OPERABLE.

In MODE 5 or 6, the temperature is to be ≤ 200°F and pressure is maintained low or at atmospheric pressure. Since the temperatures and pressures are far lower than those for MODES 1, 2, 3, and 4, the likelihood of leakage and crack propagation are much smaller. Therefore, the requirements of this LCO are not applicable in MODES 5 and 6.

ACTIONS

The Actions are modified by a Note that indicates that the provisions of LCO 3.0.4 are not applicable. As a result, a MODE change is allowed when the required monitors are inoperable.

BASES

ACTIONS (continued)

This allowance is provided because other instrumentation is available to monitor for RCS leakage.

A.1 and A.2

With the required containment sump flow monitor inoperable, no other form of sampling can provide the equivalent information; however, the containment atmosphere radioactivity monitor or containment fan cooler unit will provide indications of changes in leakage. Together with the atmosphere monitor, the periodic surveillance for RCS water inventory balance, SR 3.4.13.1, must be performed at an increased frequency of 24 hours to provide information that is adequate to detect leakage.

Restoration of the required sump flow monitor to OPERABLE status within a Completion Time of 30 days is required to regain the function after the monitor's failure. This time is acceptable, considering the Frequency and adequacy of the RCS water inventory balance required by Required Action A.1.

B.1.1, B.1.2, B.2.1 and B.2.2

With both gaseous and particulate containment atmosphere radioactivity monitoring instrumentation channels inoperable, alternative action is required. Either grab samples of the containment atmosphere must be taken and analyzed or water inventory balances, in accordance with SR 3.4.13.1, must be performed to provide alternate periodic information.

With a sample obtained and analyzed or water inventory balance performed every 24 hours, the reactor may be operated for up to 30 days to allow restoration of the required containment atmosphere radioactivity monitors. Alternatively, continued operation is allowed if the air cooler unit condensate measuring system is OPERABLE, provided grab samples are taken or water inventory balance performed every 24 hours.

The 24 hour interval provides periodic information that is adequate to detect leakage. The 30 day Completion Time recognizes at least one other form of leakage detection is available.

ACTIONS (continued)

C.1 and C.2

With the required containment fan cooler unit condensate measuring system inoperable, alternative action is again required. Either SR 3.4.15.1 must be performed or water inventory balances, in accordance with SR 3.4.13.1, must be performed to provide alternate periodic information. Provided a CHANNEL CHECK is performed every 8 hours or a water inventory balance is performed every 24 hours, reactor operation may continue while awaiting restoration of the containment fan cooler unit condensate measuring system to OPERABLE status.

The 24 hour interval provides periodic information that is adequate to detect RCS LEAKAGE.

D.1 and D.2

With the required containment atmosphere radioactivity monitor and the required containment fan cooler unit condensate measuring system inoperable, the only means of detecting leakage is the containment sump flow monitor. This Condition does not provide the required diverse means of leakage detection. The Required Action is to restore either of the inoperable required monitors to OPERABLE status within 30 days to regain the intended leakage detection diversity. The 30 day Completion Time ensures that the plant will not be operated in a reduced configuration for a lengthy time period.

E.1 and E.2

If a Required Action of Condition A, B, C, or D cannot be met, the plant must be brought to a MODE in which the requirement does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours.

The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

BASES

ACTIONS (continued)

F.1

With all required monitors inoperable, no automatic means of monitoring leakage are available, and immediate plant shutdown in accordance with LCO 3.0.3 is required.

SURVEILLANCE REQUIREMENTS

SR 3.4.15.1

SR 3.4.15.1 requires the performance of a CHANNEL CHECK of the required containment atmosphere radioactivity monitor. The check gives reasonable confidence that the channel is operating properly. The Frequency of 12 hours is based on instrument reliability and is reasonable for detecting off normal conditions.

SR 3.4.15.2

SR 3.4.15.2 requires the performance of a COT on the required containment atmosphere radioactivity monitor. The test ensures that the monitor can perform its function in the desired manner. The test verifies the alarm setpoint and relative accuracy of the instrument string. The Frequency of 92 days considers instrument reliability, and operating experience has shown that it is proper for detecting degradation.

SR 3.4.15.3, SR 3.4.15.4 and SR 3.4.15.5

These SRs require the performance of a CHANNEL CALIBRATION for each of the RCS leakage detection instrumentation channels. The calibration verifies the accuracy of the instrument string, including the instruments located inside containment. The Frequency of 24 months is a typical refueling cycle and considers channel reliability. Again, operating experience has proven that this Frequency is acceptable.

BASES

REFERENCES

1. 10 CFR 50, Appendix A, Section IV, GDC 30.
2. FSAR, Section 6.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.16 RCS Specific Activity

BASES

BACKGROUND

The maximum dose to the whole body and the thyroid that an individual at the site boundary can receive for 2 hours during an accident is specified in 10 CFR 100 (Ref. 1). The limits on specific activity ensure that the doses are held to a small fraction of the 10 CFR 100 limits during analyzed transients and accidents.

The RCS specific activity LCO limits the allowable concentration level of radionuclides in the reactor coolant. The LCO limits are established to minimize the offsite radioactivity dose consequences in the event of a steam generator tube rupture (SGTR) accident.

The LCO contains specific activity limits for both DOSE EQUIVALENT I-131 and gross specific activity. The allowable levels are intended to limit the 2 hour dose at the site boundary to a small fraction of the 10 CFR 100 dose guideline limits. The limits in the LCO are standardized, based on parametric evaluations of offsite radioactivity dose consequences for typical site locations.

The parametric evaluations showed the potential offsite dose levels for a SGTR accident were an appropriately small fraction of the 10 CFR 100 dose guideline limits. Each evaluation assumes a broad range of site applicable atmospheric dispersion factors in a parametric evaluation.

APPLICABLE SAFETY ANALYSES

The LCO limits on the specific activity of the reactor coolant ensures that the resulting 2 hour doses at the site boundary will not exceed a small fraction of the 10 CFR 100 dose guideline limits following a SGTR accident. The SGTR safety analysis (Ref. 2) assumes the specific activity of the reactor coolant at the LCO limit and an existing reactor coolant steam

BASES

APPLICABLE SAFETY ANALYSES (continued)

generator (SG) tube leakage rate of 1 gpm. The safety analysis assumes the specific activity of the secondary coolant at its limit of 0.1 μCi/gm DOSE EQUIVALENT I-131 from LCO 3.7.17, "Secondary Specific Activity."

The analysis for the SGTR accident establishes the acceptance limits for RCS specific activity. Reference to this analysis is used to assess changes to the unit that could affect RCS specific activity, as they relate to the acceptance limits.

The analysis is for two cases of reactor coolant specific activity. One case assumes specific activity at 1.0 μCi/gm DOSE EQUIVALENT I-131 with a concurrent large iodine spike that increases the I-131 activity in the reactor coolant by a factor of about 50 immediately after the accident. The second case assumes the initial reactor coolant iodine activity at 60.0 μCi/gm DOSE EQUIVALENT I-131 due to a pre-accident iodine spike caused by an RCS transient. In both cases, the noble gas activity in the reactor coolant assumes 1% failed fuel, which closely equals the LCO limit of $100/\bar{E}$ μCi/gm for gross specific activity.

The analysis also assumes a loss of offsite power at the same time as the SGTR event. The SGTR causes a reduction in reactor coolant inventory. The reduction initiates a reactor trip from a low pressurizer pressure signal or an RCS overtemperature ΔT signal.

The coincident loss of offsite power causes the steam dump valves to close to protect the condenser. The rise in pressure in the ruptured SG discharges radioactively contaminated steam to the atmosphere through the SG atmospheric dump valves (ADVs) and the main steam safety valves. The unaffected SGs remove core decay heat by venting steam to the atmosphere until the cooldown ends.

The safety analysis shows the radiological consequences of an SGTR accident are within a small fraction of the Reference 1 dose guideline limits. Operation with iodine specific activity levels greater than the LCO limit is permissible, if the activity levels do not exceed the limits shown in Figure 3.4.16-1, in the

BASES

APPLICABLE SAFETY ANALYSES (continued)

applicable specification, for more than 48 hours. The safety analysis has concurrent and pre-accident iodine spiking levels up to 60.0 μCi/gm DOSE EQUIVALENT I-131.

The remainder of the above limit permissible iodine levels shown in Figure 3.4.16-1 are acceptable because of the low probability of a SGTR accident occurring during the established 48 hour time limit. The occurrence of an SGTR accident at these permissible levels could increase the site boundary dose levels, but still be within 10 CFR 100 dose guideline limits.

The limits on RCS specific activity are also used for establishing standardization in radiation shielding and plant personnel radiation protection practices.

RCS specific activity satisfies Criterion 2 of 10 CFR 50.36.

LCO

The specific iodine activity is limited to 1.0 μCi/gm DOSE EQUIVALENT I-131, and the gross specific activity in the reactor coolant is limited to the number of μCi/gm equal to 100 divided by $\bar{E}$ (average disintegration energy of the sum of the average beta and gamma energies of the coolant nuclides). The limit on DOSE EQUIVALENT I-131 ensures the 2 hour thyroid dose to an individual at the site boundary during the Design Basis Accident (DBA) will be a small fraction of the allowed thyroid dose. The limit on gross specific activity ensures the 2 hour whole body dose to an individual at the site boundary during the DBA will be a small fraction of the allowed whole body dose.

The SGTR accident analysis (Ref. 2) shows that the 2 hour site boundary dose levels are within acceptable limits. Violation of the LCO may result in reactor coolant radioactivity levels that could, in the event of an SGTR, lead to site boundary doses that exceed the 10 CFR 100 dose guideline limits.

BASES

APPLICABILITY

In MODES 1 and 2, and in MODE 3 with RCS average temperature ≥ 500°F, operation within the LCO limits for DOSE EQUIVALENT I-131 and gross specific activity are necessary to contain the potential consequences of an SGTR to within the acceptable site boundary dose values.

For operation in MODE 3 with RCS average temperature < 500°F, and in MODES 4 and 5, the release of radioactivity in the event of a SGTR is unlikely since the saturation pressure of the reactor coolant is below the lift pressure settings of the main steam safety valves.

ACTIONS

A.1 and A.2

With the DOSE EQUIVALENT I-131 greater than the LCO limit, samples at intervals of 4 hours must be taken to demonstrate that the limits of Figure 3.4.16-1 are not exceeded. The Completion Time of 4 hours is required to obtain and analyze a sample. Sampling is done to establish the trend.

The DOSE EQUIVALENT I-131 must be restored to within limits within 48 hours. The Completion Time of 48 hours is required to allow operation to continue, if the limit violation resulted from normal iodine spiking.

A Note to the Required Actions of Condition A excludes the MODE change restriction of LCO 3.0.4. This exception allows entry into the applicable MODE(S) while relying on the ACTIONS even though the ACTIONS may eventually require plant shutdown. This exception is acceptable due to the significant conservatism incorporated into the specific activity limit, the low probability of an event which is limiting due to exceeding this limit, and the ability to restore transient specific activity excursions while the plant remains at, or proceeds to power operation.

B.1

With the gross specific activity in excess of the allowed

BASES

ACTIONS

B.1 (continued)

limit, the unit must be placed in a MODE in which the requirement does not apply.

Placing the plant in MODE 3 with RCS average temperature < 500°F lowers the saturation pressure of the reactor coolant below the setpoints of the main steam safety valves and prevents venting the SG to the environment in an SGTR event. The allowed Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 below 500°F from full power conditions in an orderly manner and without challenging plant systems.

C.1

If a Required Action and the associated Completion Time of Condition A is not met or if the DOSE EQUIVALENT I-131 is in the unacceptable region of Figure 3.4.16-1, the reactor must be brought to MODE 3 with RCS average temperature < 500°F within 6 hours. The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 below 500°F from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.16.1

SR 3.4.16.1 requires performing a gamma isotopic analysis as a measure of the gross specific activity of the reactor coolant at least once every 7 days. While basically a quantitative measure of radionuclides with half lives longer than 10 minutes, excluding iodines, this measurement is the sum of the degassed gamma activities and the gaseous gamma activities in the sample taken. This Surveillance provides an indication of any increase in gross specific activity.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.16.1 (continued)

Trending the results of this Surveillance allows proper remedial action to be taken before reaching the LCO limit under normal operating conditions. The Surveillance is applicable in MODES 1 and 2, and in MODE 3 with T_{avg} at least 500°F. The 7 day Frequency considers the low probability of a gross fuel failure during the time.

SR 3.4.16.2

This Surveillance is performed in MODE 1 only to ensure iodine remains within limit during normal operation and following fast power changes when fuel failure is more apt to occur. The 14 day Frequency is adequate to trend changes in the iodine activity level, considering gross activity is monitored every 7 days. The Frequency, between 2 and 6 hours after a power change ≥ 15% RTP within a 1 hour period, is established because the iodine levels peak during this time following fuel failure; samples at other times would provide inaccurate results.

SR 3.4.16.3

A radiochemical analysis for $\bar{E}$ determination is required every 184 days (6 months) with the plant operating in MODE 1 equilibrium conditions. The $\bar{E}$ determination directly relates to the LCO and is required to verify plant operation within the specified gross activity LCO limit. The analysis for $\bar{E}$ is a measurement of the average energies per disintegration for isotopes with half lives longer than 10 minutes, excluding iodines and non-gamma emitters. The 10 minute limit on half-lives ensures that Xenon-138 is included in the determination of $\bar{E}$. The Frequency of 184 days recognizes $\bar{E}$ does not change rapidly.

This SR has been modified by a Note that indicates sampling is required to be performed within 31 days after a minimum of 2 effective full power days and 20 days of MODE 1 operation have elapsed since the reactor was last subcritical for at least 48 hours. This ensures that the radioactive materials are at

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.16.3 (continued)

equilibrium so the analysis for $\bar{E}$ is representative and not skewed by a crud burst or other similar event.

REFERENCES

1. 10 CFR 100.11, 1973.
2. FSAR, Section 14.2.

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Improved

Technical Specifications

Conversion Submittal

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B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.1 Accumulators

BASES

BACKGROUND

The functions of the ECCS accumulators are to supply water to the reactor vessel during the blowdown phase of a loss of coolant accident (LOCA), to provide inventory to help accomplish the refill phase that follows thereafter, and to provide Reactor Coolant System (RCS) makeup for any LOCA that reduces RCS pressure to below the accumulator pressure.

The blowdown phase of a large break LOCA is the initial period of the transient during which the RCS departs from equilibrium conditions, and heat from fission product decay, hot internals, and the vessel continues to be transferred to the reactor coolant. The blowdown phase of the transient ends when the RCS pressure falls to a value approaching that of the containment atmosphere.

In the refill phase of a LOCA, which immediately follows the blowdown phase, reactor coolant inventory has vacated the core through steam flashing and ejection out through the break. The core is essentially in adiabatic heatup. The balance of accumulator inventory is then available to help fill voids in the lower plenum and reactor vessel downcomer so as to establish a recovery level at the bottom of the core and ongoing reflood of the core with the addition of safety injection (SI) water.

The accumulators are pressure vessels partially filled with borated water and pressurized with nitrogen gas. The accumulators are passive components, since no operator or control actions are required in order for them to perform their function. Internal accumulator tank pressure is sufficient to discharge the accumulator contents to the RCS, if RCS pressure decreases below the accumulator pressure.

Each accumulator is piped into an RCS cold leg via an accumulator line and is isolated from the RCS by a motor operated isolation valve and two check valves in series.

BASES

BACKGROUND (continued)

The accumulator size, water volume, and nitrogen cover pressure are selected so that three of the four accumulators are sufficient to partially cover the core before significant clad melting or zirconium water reaction can occur following a LOCA. The need to ensure that three accumulators are adequate for this function is consistent with the LOCA assumption that the entire contents of one accumulator will be lost via the RCS pipe break during the blowdown phase of the LOCA.

APPLICABLE SAFETY ANALYSES

The accumulators are assumed OPERABLE in both the large and small break LOCA analyses at full power (Ref. 1). These are the Design Basis Accidents (DBAs) that establish the acceptance limits for the accumulators. Reference to the analyses for these DBAs is used to assess changes in the accumulators as they relate to the acceptance limits.

In performing the LOCA calculations, conservative assumptions are made concerning the availability of ECCS flow. In the early stages of a LOCA, with or without a loss of offsite power, the accumulators provide the sole source of makeup water to the RCS. The assumption of loss of offsite power is required by regulations and conservatively imposes a delay wherein the ECCS pumps cannot deliver flow until the emergency diesel generators start, come to rated speed, and go through their timed loading sequence. In cold leg break scenarios, the entire contents of one accumulator are assumed to be lost through the break.

The limiting large break LOCA is a double ended guillotine break at the discharge of the reactor coolant pump. During this event, the accumulators discharge to the RCS as soon as RCS pressure decreases to below accumulator pressure.

As a conservative estimate, no credit is taken for ECCS pump flow until an effective delay has elapsed. This delay accounts for the diesels starting and the pumps being loaded and delivering full flow. The delay time is conservatively set with an additional 2 seconds to account for SI signal generation. During

BASES

APPLICABLE SAFETY ANALYSES (continued)

this time, the accumulators are analyzed as providing the sole source of emergency core cooling. No operator action is assumed during the blowdown stage of a large break LOCA.

The worst case small break LOCA analyses also assume a time delay before pumped flow reaches the core. For the larger range of small breaks, the rate of blowdown is such that the increase in fuel clad temperature is terminated solely by the accumulators, with pumped flow then providing continued cooling. As break size decreases, the accumulators and high head safety injection (HHSI) pumps both play a part in terminating the rise in clad temperature. As break size continues to decrease, the role of the accumulators continues to decrease until they are not required and the HHSI pumps become solely responsible for terminating the temperature increase.

This LCO helps to ensure that the following acceptance criteria established for the ECCS by 10 CFR 50.46 (Ref. 2) will be met following a LOCA:

a. Maximum fuel element cladding temperature is ≤ 2200°F;

b. Maximum cladding oxidation is ≤ 0.17 times the total cladding thickness before oxidation;

c. Maximum hydrogen generation from a zirconium water reaction is ≤ 0.01 times the hypothetical amount that would be generated if all of the metal in the cladding cylinders surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react; and

d. Core is maintained in a coolable geometry.

Since the accumulators discharge during the blowdown phase of a LOCA, they do not contribute to the long term cooling requirements of 10 CFR 50.46.

For both the large and small break LOCA analyses, a nominal contained accumulator water volume is used. The contained water volume is the same as the deliverable volume for the

BASES

APPLICABLE SAFETY ANALYSES (continued)

accumulators, since the accumulators are emptied, once discharged.

Accumulator tank size and accumulator water volume directly affect the volume of nitrogen cover gas whose expansion produces the passive injection and thus affects injection rate. The amount of water is also important since the accumulator water which has not been injected and bypassed during blowdown is primarily responsible for filling the lower plenum (refill) and downcomer. The elevation head of the downcomer water provides the driving force for core reflooding (Ref. 3).

For large break LOCAs, changes in accumulator water volume can result in either improved or worsened analysis results; therefore, a nominal accumulator water volume of 795 cubic feet is modeled in the analysis (Ref. 3).

For small break LOCAs, changes in accumulator water volume are not significant because the clad temperature transient is terminated before the accumulators empty; therefore, a nominal accumulator water volume of 795 cubic feet is modeled in the analysis (Ref. 3).

The minimum boron concentration setpoint is used in the post LOCA boron concentration calculation. The calculation is performed to assure reactor subcriticality in a post LOCA environment. Of particular interest is the large break LOCA, since no credit is taken for control rod assembly insertion. A reduction in the accumulator minimum boron concentration would produce a subsequent reduction in the available containment sump concentration for post LOCA shutdown and an increase in the maximum sump pH. The maximum boron concentration is used in determining the cold leg to hot leg recirculation injection switchover time and minimum sump pH.

The large and small break LOCA analyses are performed at the minimum nitrogen cover pressure, since sensitivity analyses have demonstrated that higher nitrogen cover pressure results in a computed peak clad temperature benefit. The maximum nitrogen

BASES

APPLICABLE SAFETY ANALYSES (continued)

cover pressure limit prevents injection of nitrogen into the RCS, accumulator relief valve actuation, and ultimately preserves accumulator integrity.

The effects on containment mass and energy releases from the accumulators are accounted for in the appropriate analyses (Refs. 3 and 4).

The accumulators satisfy Criterion 3 of 10 CFR 50.36.

LCO

The LCO establishes the minimum conditions required to ensure that the accumulators are available to accomplish their core cooling safety function following a LOCA. Four accumulators are required to ensure that 100% of the contents of three of the accumulators will reach the core during a LOCA. This is consistent with the assumption that the contents of one accumulator spill through the break. If less than three accumulators are injected during the blowdown phase of a LOCA, the ECCS acceptance criteria of 10 CFR 50.46 (Ref. 2) could be violated.

For an accumulator to be considered OPERABLE, the isolation valve must be fully open, power removed above 2000 psig, and the limits established in the SRs for contained volume, boron concentration, and nitrogen cover pressure must be met.

APPLICABILITY

In MODES 1 and 2, and in MODE 3 with RCS pressure > 1000 psig, the accumulator OPERABILITY requirements are based on full power operation. Although cooling requirements decrease as power decreases, the accumulators are still required to provide core cooling as long as elevated RCS pressures and temperatures exist.

This LCO is only applicable at pressures > 1000 psig. At pressures ≤ 1000 psig, the rate of RCS blowdown is such that the ECCS pumps can provide adequate injection to ensure that peak clad temperature remains below the 10 CFR 50.46 (Ref. 2) limit of 2200°F.

BASES

APPLICABILITY (continued)

In MODE 3, with RCS pressure ≤ 1000 psig, and in MODES 4, 5, and 6, the accumulator motor operated discharge isolation valves are closed to isolate the accumulators from the RCS. This allows RCS cooldown and depressurization without discharging the accumulators into the RCS or requiring depressurization of the accumulators.

Note 1 provides an exception to SR 3.5.1.1 and SR 3.5.1.5 and specifies that all accumulator discharge isolation valves may be closed and energized for up to 8 hours during the performance of reactor coolant system hydrostatic testing. This allowance is necessary because limits imposed by the Pressure/Temperature Limits for a hydrostatic leak test, could, in some instances, require reactor coolant system hydrostatic testing above 350°F (Mode 3). This allowance is acceptable because hydrostatic testing is performed in MODE 3 when the need for the accumulators is reduced and Note 1 limits the duration to the time needed to perform required testing.

Note 2 also provides an exception to SR 3.5.1.1 and SR 3.5.1.5 and specifies that one accumulator discharge isolation valve may be closed and energized in MODE 3 for up to 8 hours for accumulator check valve leakage testing. This allowance is acceptable because testing is limited to MODE 3 when the need for the accumulators is reduced and Note 2 limits the duration to the time needed to perform required testing.

ACTIONS

A.1

If the boron concentration of one accumulator is not within limits, it must be returned to within the limits within 72 hours. In this Condition, ability to maintain subcriticality or minimum boron precipitation time may be reduced. The boron in the accumulators contributes to the assumption that the combined ECCS water in the partially recovered core during the early reflooding phase of a large break LOCA is sufficient to keep that portion of the core subcritical. One accumulator below the minimum boron concentration limit, however, will have no effect on available

BASES

ACTIONS

A.1 (continued)

ECCS water and an insignificant effect on core subcriticality during reflood. Boiling of ECCS water in the core during reflood concentrates boron in the saturated liquid that remains in the core. In addition, current analysis techniques demonstrate that the accumulators do not discharge following a large main steam line break. Even if they do discharge, their impact is minor and not a design limiting event. Thus, 72 hours is allowed to return the boron concentration to within limits.

B.1

If one accumulator is inoperable for a reason other than boron concentration, the accumulator must be returned to OPERABLE status within 1 hour. In this Condition, the required contents of three accumulators cannot be assumed to reach the core during a LOCA. Due to the severity of the consequences should a LOCA occur in these conditions, the 1 hour Completion Time to open the valve, remove power to the valve, or restore the proper water volume or nitrogen cover pressure ensures that prompt action will be taken to return the inoperable accumulator to OPERABLE status. The Completion Time minimizes the potential for exposure of the plant to a LOCA under these conditions.

C.1 and C.2

If the accumulator cannot be returned to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 6 hours and reactor coolant pressure reduced to ≤ 1000 psig within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

D.1

If more than one accumulator is inoperable, the plant is in a condition outside the accident analyses; therefore, LCO 3.0.3 must be entered immediately.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.1.1

Each accumulator valve should be verified to be fully open every 12 hours. This verification ensures that the accumulators are available for injection and ensures timely discovery if a valve should be less than fully open. If a discharge isolation valve is not fully open, the rate of injection to the RCS would be reduced. Although a motor operated valve position should not change with power removed, a closed valve could result in not meeting accident analyses assumptions. This Frequency is considered reasonable in view of other administrative controls that ensure a mispositioned isolation valve is unlikely.

SR 3.5.1.2 and SR 3.5.1.3

Every 12 hours, borated water volume and nitrogen cover pressure are verified for each accumulator. This Frequency is sufficient to ensure adequate injection during a LOCA. Because of the static design of the accumulator, a 12 hour Frequency usually allows the operator to identify changes before limits are reached. Operating experience has shown this Frequency to be appropriate for early detection and correction of off normal trends.

SR 3.5.1.4

The boron concentration should be verified to be within required limits for each accumulator every 31 days since the static design of the accumulators limits the ways in which the concentration can be changed. The 31 day Frequency is adequate to identify changes that could occur from mechanisms such as stratification or inleakage. Sampling the affected accumulator within 6 hours after an increase of 3 cubic feet will identify whether inleakage has caused a reduction in boron concentration to below the required limit. Considering the nominal accumulator volume of 795 cubic feet of water, inleakage of 3 cubic feet of pure water would result in a boron concentration reduction of less than 1%. An increase in the accumulator volume of 3 cubic feet causes a change of approximately 10% in the indicated accumulator level. It is not necessary to verify boron concentration if the added

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.1.4 (continued)

water inventory is from the refueling water storage tank (RWST), because the water contained in the RWST is within the accumulator boron concentration requirements. This is consistent with the recommendation of NUREG-1366 (Ref. 4).

SR 3.5.1.5

Verification every 31 days that power is removed from each accumulator discharge isolation valve operator when the pressurizer pressure is ≥ 2000 psig ensures that an active failure could not result in the undetected closure of an accumulator motor operated isolation valve. If this were to occur, only two accumulators would be available for injection given a single failure coincident with a LOCA. Since power is removed under administrative control, the 31 day Frequency will provide adequate assurance that power is removed.

This SR allows power to be supplied to the motor operated discharge isolation valves when pressurizer pressure is < 2000 psig, thus allowing operational flexibility by avoiding unnecessary delays to manipulate the breakers during plant startups or shutdowns.

Should closure of a valve occur, the SI signal provided to the valves would open a closed valve in the event of a LOCA.

REFERENCES

1. FSAR, Chapter 6.
2. 10 CFR 50.46.
3. FSAR, Chapter 14.
4. NUREG-1366, February 1990.

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.2 ECCS – Operating

BASES

BACKGROUND

The function of the ECCS is to provide core cooling and negative reactivity to ensure that the reactor core is protected after any of the following accidents:

a. Loss of coolant accident (LOCA), coolant leakage greater than the capability of the normal charging system;

b. Rod ejection accident;

c. Loss of secondary coolant accident; and

d. Steam generator tube rupture (SGTR).

The addition of negative reactivity is designed primarily for the loss of secondary coolant accident where primary cooldown could add enough positive reactivity to achieve criticality and return to significant power.

There are three phases of ECCS operation: injection, cold leg recirculation, and hot leg recirculation. In the injection phase, water is taken from the refueling water storage tank (RWST) and injected into the Reactor Coolant System (RCS) through the cold legs. When sufficient water is removed from the RWST to ensure that enough boron has been added to maintain the reactor subcritical and the recirculation and containment sumps have enough water to supply the required net positive suction head to the ECCS pumps, suction is switched to the recirculation sump or containment sump for cold leg recirculation. After between 14.3 and 24 hours, the ECCS flow is shifted to the hot leg recirculation phase to provide a backflush, which would reduce the boiling in the top of the core and any resulting boron precipitation.

The ECCS FUNCTION is provided by three separate ECCS systems: high head safety injection (HHSI), residual heat removal (RHR) injection, and containment recirculation. Each ECCS system is divided into subsystems as follows:

BASES

BACKGROUND (Continued)

- HHSI System is divided into three 50% capacity subsystems. Each HHSI subsystem consists of one pump as well as associated piping and valves to transfer water from the suction source to the core. HHSI subsystem 32 is OPERABLE when capable of injecting using the flow path associated with either HHSI subsystem 31 or 33. Note that the HHSI pumps have a shutoff head of approximately 1500 psig. Therefore, IP3 is classified as a low head safety injection plant.

- RHR injection System is divided into two 100% capacity subsystems. Each ECCS RHR subsystem consists of one RHR pump and one RHR heat exchanger as well as associated piping and valves to transfer water from the suction source to the core. Although either RHR heat exchanger may be credited for either RHR subsystem, one RHR heat exchanger must be OPERABLE for each OPERABLE RHR injection subsystem.

- Containment Recirculation is divided into two 100% capacity subsystems. Each subsystem consists of one Containment Recirculation pump and one RHR heat exchanger as well as associated piping and valves to transfer water from the suction source to the core. Although either RHR heat exchanger may be credited for either Recirculation subsystem, one RHR heat exchanger must be OPERABLE for each OPERABLE Containment Recirculation subsystem.

The three ECCS systems (3 HHSI, 2 RHR and 2 Recirculation) are grouped into three trains (5A, 2A/3A and 6A) such that any 2 of the 3 trains are capable of meeting all ECCS capability assumed in the accident analysis. Each ECCS train consists of the following:

a. ECCS Train 5A includes subsystems HHSI 31 and containment recirculation 31;

b. ECCS Train 2A/3A includes subsystems HHSI 32 and RHR 31; and,

BASES

BACKGROUND (Continued)

c. ECCS Train 6A includes subsystems HHSI 33, RHR 32, and containment recirculation 32.

The ECCS trains use the same designation as the Safeguards Power Trains required by LCO 3.8.9, Distribution Systems - Operating, with Safeguards Power Train 5A supported by DG 33, Safeguards Power Train 2A/23 supported by DG 31, Safeguards Power Train 6A supported by DG 32.

The ECCS accumulators and the RWST are also part of the ECCS, but are not considered part of an ECCS flow path as described by this LCO.

The ECCS flow paths consist of piping, valves, heat exchangers, and pumps such that water from the RWST can be injected into the RCS following the accidents described in this LCO. The major components of each subsystem are the high head safety injection pumps, the RHR pumps, heat exchangers, and the containment recirculation pumps. This interconnecting and redundant subsystem design provides the operators with the ability to utilize components from different trains to achieve the required 100% flow to the core.

During the injection phase of LOCA recovery, a suction header supplies water from the RWST to the HHSI and RHR pumps. The discharge from the HHSI and RHR pumps feed injection lines to each of the RCS cold legs. Control valves are set to balance the HHSI flow to the RCS. This balance ensures sufficient flow to the core to meet the analysis assumptions following a LOCA in one of the RCS cold legs.

During the recirculation phase of LOCA recovery, the containment recirculation pumps take suction from the containment recirculation sump and direct flow through the RHR heat exchangers to the cold legs. The RHR pumps can be used to provide a backup method of recirculation in which case the RHR pump suction is transferred to the containment sump. The RHR pumps then supply recirculation flow directly or supply the suction of the HHSI pumps. Initially, recirculation is through

BASES

BACKGROUND (Continued)

the same paths as the injection phase. Subsequently, recirculation injection is split between the hot and cold legs.

The ECCS also functions to supply borated water to the reactor core following increased heat removal events, such as a main steam line break (MSLB). The limiting design conditions occur when the negative moderator temperature coefficient is highly negative, such as at the end of each cycle.

During low temperature conditions in the RCS, limitations are placed on the maximum number of HHSI pumps that may be OPERABLE. Refer to the Bases for LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP) System," for the basis of these requirements.

The ECCS subsystems, exccept for the containment recirculation subsystems, are actuated upon receipt of an SI signal. The actuation of safeguard loads is accomplished in a programmed time sequence. If offsite power is available, the safeguard loads start immediately in the programmed sequence. If offsite power is not available, the Engineered Safety Feature (ESF) buses shed normal operating loads and are connected to the emergency diesel generators (EDGs). Safeguard loads are then actuated in the programmed time sequence. The time delay associated with diesel starting, sequenced loading, and pump starting determines the time required before pumped flow is available to the core following a LOCA.

The active ECCS components, along with the passive accumulators and the RWST covered in LCO 3.5.1, "Accumulators," and LCO 3.5.4, "Refueling Water Storage Tank (RWST)," provide the cooling water necessary to meet GDC 35 (Ref. 1).

BASES

APPLICABLE SAFETY ANALYSES

The LCO helps to ensure that the following acceptance criteria for the ECCS, established by 10 CFR 50.46 (Ref. 2), will be met following a LOCA:

a. Maximum fuel element cladding temperature is ≤ 2200°F;

b. Maximum cladding oxidation is ≤ 0.17 times the total cladding thickness before oxidation;

c. Maximum hydrogen generation from a zirconium water reaction is ≤ 0.01 times the hypothetical amount generated if all of the metal in the cladding cylinders surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react;

d. Core is maintained in a coolable geometry; and

e. Adequate long term core cooling capability is maintained.

The LCO also limits the potential for a post trip return to power following an MSLB event.

Each ECCS subsystem is taken credit for in a large break LOCA event at full power (Refs. 3 and 4). This event establishes the requirement for runout flow for the ECCS pumps, as well as the maximum response time for their actuation. The HHSI pumps are credited in a small break LOCA event. The OPERABILITY requirements for the ECCS are based on the following LOCA analysis assumptions:

a. A large break LOCA event, with loss of offsite power and a single failure disabling one EDG; and

b. A small break LOCA event, with a loss of offsite power and a single failure disabling one EDG.

During the blowdown stage of a LOCA, the RCS depressurizes as primary coolant is ejected through the break into the containment. The nuclear reaction is terminated either by moderator voiding during large breaks or control rod insertion

BASES

APPLICABLE SAFETY ANALYSES (continued)

for small breaks. Following depressurization, emergency cooling water is injected into the cold legs, flows into the downcomer, fills the lower plenum, and refloods the core.

The effects on containment mass and energy releases are accounted for in appropriate analyses (Refs. 3 and 4). The LCO ensures that an ECCS train will deliver sufficient water to match boiloff rates soon enough to minimize the consequences of the core being uncovered following a large LOCA. It also ensures that the HHSI pumps will deliver sufficient water and boron during a small LOCA to maintain core subcriticality. For a small break LOCA, the steam generators continue to serve as the heat sink, providing part of the required core cooling.

The ECCS trains satisfy Criterion 3 of 10 CFR 50.36.

LCO

In MODES 1, 2, and 3, three ECCS trains are required to ensure that sufficient ECCS flow is available, assuming a single failure affecting any one train. Additionally, individual components within the ECCS trains may be called upon to mitigate the consequences of other transients and accidents.

In MODES 1, 2, and 3, the ECCS consists of the following:

a. ECCS Train 5A includes HHSI subsystem 31 and containment recirculation subsystem 31;

b. ECCS Train 2A/3A includes HHSI subsystem 32 and RHR subsystem 31; and,

c. ECCS Train 6A includes HHSI subsystem 33, RHR subsystem 32, and containment recirculation subsystem 32.

Each HHSI subsystem consists of one pump as well as associated instrumentation, piping and valves to transfer water from the suction source to the core. HHSI subsystem 32 is OPERABLE when capable of injecting using the flow path associated with either HHSI subsystem 31 or 33.

BASES

LCO (continued)

Each ECCS RHR subsystem consists of one RHR pump and one RHR heat exchanger as well as associated instrumentation, piping and valves to transfer water from the suction source to the core. Although either RHR heat exchanger may be credited for either RHR subsystem, one RHR heat exchanger must be OPERABLE for each OPERABLE RHR injection subsystem.

Each containment recirculation subsystem consists of one Containment Recirculation pump and one RHR heat exchanger as well as associated instrumentation piping and valves to transfer water from the suction source to the core. Although either RHR heat exchanger may be credited for either Recirculation subsystem, one RHR heat exchanger must be OPERABLE for each OPERABLE Containment Recirculation subsystem. Note that Recirculation pump OPERABILITY requires the functional availability of the associated auxiliary component cooling water pump.

During an event requiring ECCS actuation, a flow path is required to provide an abundant supply of water from the RWST to the RCS via the HHSI and RHR pumps and their supply header to each of the four cold leg injection nozzles (8 cold leg injection nozzles for the HHSI pumps). In the long term, this flow path may be switched to take its supply from the containment recirculation sump using the containment recirculation pumps or, alternately, the containment sump using the RHR pumps to supply its flow to the RCS hot and cold legs, either directly into the RCS or via the HHSI pumps.

The flow path for each train must maintain its designed independence to ensure that no single failure can disable more than one ECCS train (except as described in Reference 5).

As indicated in Note 1, the SI flow paths may be isolated for 2 hours in MODE 3, under controlled conditions, to perform pressure isolation valve testing per SR 3.4.14.1. This is acceptable because the flow paths are readily restorable from the control room or the valves are opened under administrative controls that ensure prompt closure when required. These administrative controls consist of stationing a dedicated

BASES

LCO (continued)

operator at the valve controls, who is in continuous communication with the control room.

As indicated in Note 2, operation in MODE 3 with ECCS trains made incapable of injecting pursuant to LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP) System," is necessary for plants with an LTOP arming temperature at or near the MODE 3 boundary temperature of 350°F. LCO 3.4.12 requires that certain pumps be made incapable of injecting at and below the LTOP arming temperature. When this temperature is at or near the MODE 3 boundary temperature, time is needed to restore the inoperable pumps to OPERABLE status.

APPLICABILITY

In MODES 1, 2, and 3, the ECCS OPERABILITY requirements for the limiting Design Basis Accident, a large break LOCA, are based on full power operation. Although reduced power would not require the same level of performance, the accident analysis does not provide for reduced cooling requirements when at lower power. The HHSI pump performance requirements are based on a small break LOCA. MODE 2 and MODE 3 requirements are bounded by the MODE 1 analysis.

This LCO is only applicable in MODE 3 and above. Below MODE 3, system functional requirements are relaxed as described in LCO 3.5.3, "ECCS – Shutdown."

In MODES 5 and 6, plant conditions are such that the probability of an event requiring ECCS injection is extremely low. Core cooling requirements in MODE 5 are addressed by LCO 3.4.7, "RCS Loops – MODE 5, Loops Filled," and LCO 3.4.8, "RCS Loops – MODE 5, Loops Not Filled." MODE 6 core cooling requirements are addressed by LCO 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation – High Water Level," and LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation – Low Water Level."

BASES

ACTIONS

A.1

With one or more trains inoperable and at least 100% of the ECCS flow equivalent (100% HHSI flow, 100% RHR injection flow, and 100% containment recirculation flow) to OPERABLE ECCS trains available, the inoperable components must be returned to OPERABLE status within 72 hours. The 72 hour Completion Time is based on an NRC reliability evaluation (Ref. 4) and is a reasonable time for repair of many ECCS components.

An ECCS train is inoperable if it is not capable of delivering design flow to the RCS. Individual components are inoperable if they are not capable of performing their design function or supporting systems are not available.

The LCO requires the OPERABILITY of a number of independent subsystems. Due to the redundancy of trains and the diversity of subsystems, the inoperability of one pump in a train does not render the ECCS incapable of performing its function. Neither does the inoperability of two different pumps, each in a different train, necessarily result in a loss of function for the ECCS. The intent of this Condition is to maintain a combination of equipment such that 100% of the ECCS flow equivalent to two OPERABLE ECCS trains remains available. This allows increased flexibility in plant operations under circumstances when pumps in redundant trains are inoperable.

An event accompanied by a loss of offsite power and the failure of an EDG can disable one ECCS train until power is restored. A reliability analysis (Ref. 4) has shown that the impact of having one full ECCS train inoperable is sufficiently small to justify continued operation for 72 hours.

Reference 5 describes situations in which one component, such as the valves governed by SR 3.5.2.1 and SR 3.5.2.6, can disable more than one ECCS train. With one or more component(s) inoperable such that 100% of the flow equivalent for HHSI, RHR and Containment Recirculation is not available, the facility is in a condition outside the accident analysis. Therefore, LCO 3.0.3 must be immediately entered.

BASES

ACTIONS (continued)

B.1 and B.2

If the inoperable trains cannot be returned to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 6 hours and MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.5.2.1

Verification of proper valve position ensures that the flow path from the ECCS pumps to the RCS is maintained. Misalignment of these valves could render more than one ECCS train inoperable. Securing these valves in position by removal of power or by key locking the control in the correct position ensures that they cannot change position as a result of an active failure or be inadvertently misaligned. These valves are of the type, described in Reference 5, that can disable the function of more than one ECCS train and invalidate the accident analyses. A 12 hour Frequency is considered reasonable in view of other administrative controls that will ensure a mispositioned valve is unlikely.

SR 3.5.2.2

Verifying the correct alignment for manual, power operated, and automatic valves in the ECCS flow paths provides assurance that the proper flow paths will exist for ECCS operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these were verified to be in the correct position prior to locking, sealing, or securing. A valve that receives an actuation signal is allowed to be in a nonaccident position provided the valve will automatically

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.2.2 (continued)

reposition within the proper stroke time. This Surveillance does not require any testing or valve manipulation. Rather, it involves verification that those valves capable of being mispositioned are in the correct position. The 31 day Frequency is appropriate because the valves are operated under administrative control, and an improper valve position would only affect a single train. This Frequency has been shown to be acceptable through operating experience.

SR 3.5.2.3

Periodic surveillance testing of ECCS pumps to detect gross degradation caused by impeller structural damage or other hydraulic component problems is required by Section XI of the ASME Code. This type of testing may be accomplished by measuring the pump developed head at only one point of the pump characteristic curve. This verifies both that the measured performance is within an acceptable tolerance of the original pump baseline performance and that the performance at the test flow is greater than or equal to the performance assumed in the plant safety analysis. SRs are specified in the Inservice Testing Program, which encompasses Section XI of the ASME Code. Section XI of the ASME Code provides the activities and Frequencies necessary to satisfy the requirements.

SR 3.5.2.4 and SR 3.5.2.5

These Surveillances demonstrate that each automatic ECCS valve actuates to the required position on an actual or simulated SI signal and that each ECCS pump starts on receipt of an actual or simulated SI signal. Note that the Containment Recirculation system is a manually initiated system and is not included as part of this SR. Additionally, this Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The 24 month Frequency is based on the need to perform these Surveillances

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.2.4 and SR 3.5.2.5 (continued)

under the conditions that apply during a plant outage and the potential for unplanned plant transients if the Surveillances were performed with the reactor at power. The 24 month Frequency is also acceptable based on consideration of the design reliability (and confirming operating experience) of the equipment. The actuation logic is tested as part of ESF Actuation System testing, and equipment performance is monitored as part of the Inservice Testing Program.

SR 3.5.2.6

Realignment of valves in the flow path on an SI signal is necessary for proper ECCS performance. These valves have stops to allow proper positioning for restricted flow to a ruptured cold leg, ensuring that the other cold legs receive at least the required minimum flow. Therefore, an improperly positioned valve could result in the inoperability of more than one injection flow path. The stops are set based on the results of the most recent ECCS operational flow test. The 24 month Frequency is based on the reasons stated in SR 3.5.2.4 and SR 3.5.2.5.

SR 3.5.2.7

Periodic inspections of each containment and recirculation sump suction inlet ensure that each is unrestricted and stays in proper operating condition. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage, on the need to have access to the location, and because of the potential for an unplanned transient if the Surveillance were performed with the reactor at power. This Frequency is sufficient to detect abnormal degradation and is confirmed by industry operating experience.

BASES

REFERENCES

1. 10 CFR 50, Appendix A, GDC 35.

2. 10 CFR 50.46.

3. FSAR, Section 14.

4. NRC Memorandum to V. Stello, Jr., from R.L. Baer, "Recommended Interim Revisions to LCOs for ECCS Components," December 1, 1975.

5. IE Information Notice No. 87-01.

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.3 ECCS – Shutdown

BASES

BACKGROUND

The Background section for Bases 3.5.2, "ECCS – Operating," is applicable to these Bases, with the following modifications.

In MODE 4, one ECCS residual heat removal (RHR) subsystem and one ECCS Recirculation subsystem are required.

The ECCS flow paths consist of piping, valves, heat exchangers, and pumps such that water from the refueling water storage tank (RWST) or the containment or recirculation sump can be injected into the Reactor Coolant System (RCS) following the accidents described in Bases 3.5.2.

APPLICABLE SAFETY ANALYSES

The Applicable Safety Analyses section of Bases 3.5.2 also applies to this Bases section.

Due to the stable conditions associated with operation in MODE 4 and the reduced probability of occurrence of a Design Basis Accident (DBA), the ECCS operational requirements are reduced. It is understood in these reductions that automatic safety injection (SI) actuation is not available. In this MODE, sufficient time exists for manual actuation of the required ECCS to mitigate the consequences of a DBA.

Only one ECCS residual heat removal (RHR) subsystem and one ECCS Recirculation subsystem are required for MODE 4. This requirement dictates that single failures are not considered during this MODE of operation. The ECCS trains satisfy Criterion 3 of 10 CFR 50.36.

LCO

In MODE 4, one ECCS residual heat removal (RHR) subsystem and one ECCS Recirculation subsystem are required to be OPERABLE to

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BASES

LCO (continued)

ensure that sufficient ECCS flow is available to the core following a DBA.

In MODE 4, ECCS requirements may be met using containment Recirculation subsystem 31 or 32 and RHR subsystem 31 or 32.

An ECCS RHR subsystem consists of one RHR pump and one RHR heat exchanger as well as associated piping and valves and instrumentation and controls needed to transfer water from the RWST or containment sump to the core. Either RHR heat exchanger may be used with either RHR pump to meet requirements for an RHR subsystem.

A containment Recirculation subsystem consists of one Containment Recirculation pump and one RHR heat exchanger as well as associated piping, valves, instrumentation and controls needed to transfer water from the recirculation sump to the core. Note that Recirculation pump OPERABILITY requires the functional availability of the associated auxiliary component cooling water pump. Either RHR heat exchanger may be used with either recirculation pump to meet requirements for a recirculation subsystem. The same RHR heat exchanger may be used to meet requirements for both the RHR subsystem and the Recirculation subsystem.

During an event requiring ECCS actuation, a flow path is required to provide an abundant supply of water from the RWST to the RCS via the RHR pumps and their respective supply headers to each of the four cold leg injection nozzles. In the long term, the recirculation flow path using the Recirculation sump or containment sump may be used to deliver its flow to the RCS cold legs.

This LCO is modified by a Note that allows an RHR subsystem to be considered OPERABLE during alignment and operation for decay heat removal, if capable of being manually realigned (remote or local) to the ECCS mode of operation and not otherwise inoperable. This allows operation in the RHR mode during MODE 4.

BASES

APPLICABILITY

In MODES 1, 2, and 3, the OPERABILITY requirements for ECCS are covered by LCO 3.5.2.

In MODE 4 with RCS temperature below 350°F, one OPERABLE ECCS residual heat removal (RHR) subsystem and one OPERABLE ECCS Recirculation subsystem is acceptable without single failure consideration, on the basis of the stable reactivity of the reactor and the limited core cooling requirements.

In MODES 5 and 6, plant conditions are such that the probability of an event requiring ECCS injection is extremely low. Core cooling requirements in MODE 5 are addressed by LCO 3.4.7, "RCS Loops – MODE 5, Loops Filled," and LCO 3.4.8, "RCS Loops – MODE 5, Loops Not Filled." MODE 6 core cooling requirements are addressed by LCO 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation – High Water Level," and LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation – Low Water Level."

ACTIONS

A.1

With no ECCS RHR subsystem OPERABLE, the plant is not prepared to respond to a loss of coolant accident or to continue a cooldown using the RHR pumps and heat exchangers. The Completion Time of immediately to initiate actions that would restore at least one ECCS RHR subsystem to OPERABLE status ensures that prompt action is taken to restore the required cooling capacity. Normally, in MODE 4, reactor decay heat is removed from the RCS by an RHR loop. If no RHR loop is OPERABLE for this function, reactor decay heat must be removed by some alternate method, such as use of the steam generators. The alternate means of heat removal must continue until the inoperable RHR loop components can be restored to operation so that decay heat removal is continuous.

With both RHR pumps and heat exchangers inoperable, it would be unwise to require the plant to go to MODE 5, where the only available heat removal system is the RHR. Therefore, the appropriate action is to initiate measures to restore one ECCS RHR subsystem and to continue the actions until the subsystem is restored to OPERABLE status.

BASES

ACTIONS (continued)

B.1

With no containment Recirculation subsystem OPERABLE, due to the inoperability of the pump or flow path from the recirculation sump, the plant is not prepared to provide long term cooling response to Design Basis Events requiring SI. The 1 hour Completion Time to restore at least one ECCS Recirculation subsystem to OPERABLE status ensures that prompt action is taken to provide the required cooling capacity or to initiate actions to place the plant in MODE 5, where a recirculation subsystem is not required.

C.1

Note: Condition C should not be entered if Condition A is applicable.

When the Required Actions of Condition B cannot be completed within the required Completion Time, a controlled shutdown should be initiated. Twenty-four hours is a reasonable time, based on operating experience, to reach MODE 5 in an orderly manner and without challenging plant systems or operators.

SURVEILLANCE REQUIREMENTS

SR 3.5.3.1

The applicable Surveillance descriptions from Bases 3.5.2 apply.

REFERENCES

The applicable references from Bases 3.5.2 apply.

B 3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

B 3.5.4 Refueling Water Storage Tank (RWST)

BASES

BACKGROUND

The RWST supplies borated water to the Chemical and Volume Control System (CVCS) during abnormal operating conditions, to the refueling cavity during refueling, to the ECCS to fill accumulators, and to the ECCS and the Containment Spray System during accident conditions.

The RWST supplies the ECCS and the Containment Spray System through separate supply headers during the injection phase of a loss of coolant accident (LOCA). Motor operated isolation valves are provided to isolate the RWST from the ECCS subsystems once the system has been transferred to the recirculation mode. The switchover to the cold leg recirculation phase is manually initiated when the RWST level has reached the low-low alarm setpoint and sufficient coolant inventory to support pump operation in recirculation mode is verified to be in the containment. Use of a single RWST to supply all of the injection trains of the ECCS and Containment Spray System is acceptable since the RWST is a passive component, and passive failures are not required to be assumed to occur coincidentally with Design Basis Events.

During normal operation in MODES 1, 2, and 3, the high head safety injection (HHSI) and residual heat removal (RHR) pumps are aligned to take suction from the RWST.

The ECCS and Containment Spray System pumps are provided with recirculation lines that ensure each pump can maintain minimum flow requirements when operating at or near shutoff head conditions.

This LCO ensures that:

a. The RWST contains sufficient borated water to support the ECCS during the injection phase;

b. Sufficient water volume exists in the recirculation sump or the containment sump to support continued operation of the

BACKGROUND (continued)

ECCS and Containment Spray System pumps at the time of transfer to the recirculation mode of cooling; and

c. The reactor remains subcritical following a LOCA or MSLB.

Insufficient water in the RWST could result in insufficient cooling capacity when the transfer to the recirculation mode occurs. Improper boron concentrations could result in a reduction of SDM or excessive boric acid precipitation in the core following the LOCA, as well as excessive caustic stress corrosion of mechanical components and systems inside the containment due to improper pH in the sumps.

APPLICABLE SAFETY ANALYSES

During accident conditions, the RWST provides a source of borated water to the ECCS and Containment Spray System pumps. As such, it provides containment cooling and depressurization, core cooling, and replacement inventory and is a source of negative reactivity for reactor shutdown (Ref. 1). The design basis transients and applicable safety analyses concerning each of these systems are discussed in the Applicable Safety Analyses section of B 3.5.2, "ECCS – Operating"; B 3.5.3, "ECCS – Shutdown"; and B 3.6.6, "Containment Spray System and Containment Fan Fooler System." These analyses are used to assess changes to the RWST in order to evaluate their effects in relation to the acceptance limits in the open analyses.

The RWST must also meet volume, boron concentration, and temperature requirements for non-LOCA events. The volume is not an explicit assumption in non-LOCA events since the required volume is a small fraction of the available volume. The deliverable volume limit is set by the LOCA and containment analyses. For the RWST, the deliverable volume is different from the total volume contained since, due to the design of the tank, more water can be contained than can be delivered.

APPLICABLE SAFETY ANALYSES (continued)

For a large break LOCA analysis, the minimum water volume limit of 195,800 gallons and the lower boron concentration limit of 2300 ppm are used to compute the post LOCA sump boron concentration necessary to assure subcriticality. The large break LOCA is the limiting case since the safety analysis assumes that all control rods are out of the core.

The upper limit on boron concentration of 2600 ppm is used to determine the maximum allowable time to switch to hot leg recirculation following a LOCA. The purpose of switching from cold leg to hot leg injection is to avoid boron precipitation in the core following the accident.

In the ECCS analysis, the containment spray temperature is assumed to be equal to the RWST lower temperature limit of 40°F. If the lower temperature limit is violated, the containment spray further reduces containment pressure, which decreases the rate at which steam can be vented out the break and increases peak clad temperature. The upper temperature limit of 110°F is used in the LOCA containment integrity analysis. Exceeding this temperature will result in higher containment pressures due to reduced containment spray cooling capacity. The minimum boron concentration is an explicit assumption in the main steam line break (MSLB) analysis to ensure the required shutdown capability. For the containment response following an MSLB, the lower limit on boron concentration and the upper limit on RWST water temperature are used to maximize the total energy release to containment.

The RWST satisfies Criterion 3 of 10 CFR 50.36.

LCO

The RWST ensures that an adequate supply of borated water is available to cool and depressurize the containment in the event of a Design Basis Accident (DBA), to cool and cover the core in the event of a LOCA, to maintain the reactor subcritical following a DBA, and to ensure adequate level in the recirculation sump and the containment sump to support ECCS pump operation in the recirculation mode.

LCO (continued)

To be considered OPERABLE, the RWST must meet the water volume, boron concentration, and temperature limits established in the SRs.

APPLICABILITY

In MODES 1, 2, 3, and 4, RWST OPERABILITY requirements are dictated by ECCS and Containment Spray System OPERABILITY requirements. Since both the ECCS and the Containment Spray System must be OPERABLE in MODES 1, 2, 3, and 4, the RWST must also be OPERABLE to support their operation. Core cooling requirements in MODE 5 are addressed by LCO 3.4.7, "RCS Loops - MODE 5, Loops Filled," and LCO 3.4.8, "RCS Loops - MODE 5, Loops Not Filled." MODE 6 core cooling requirements are addressed by LCO 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation-High Water Level," and LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation-Low Water Level."

ACTIONS

A.1

With RWST boron concentration or borated water temperature not within limits of SR 3.5.4.3 and SR 3.5.4.1, respectively, they must be returned to within limits within 8 hours. Under these conditions neither the ECCS nor the Containment Spray System can perform its design function. Therefore, prompt action must be taken to restore the tank to OPERABLE condition. The 8 hour limit to restore the RWST temperature or boron concentration to within limits was developed considering the time required to change either the boron concentration or temperature and the fact that the contents of the tank are still available for injection.

B.1

With the RWST inoperable for reasons other than Condition A (e.g., water volume), it must be restored to OPERABLE status within 1 hour.

In this Condition, neither the ECCS nor the Containment Spray System can perform its design function. Therefore, prompt action must be taken to restore the tank to OPERABLE status or to place

ACTIONS

B.1 (continued)

the plant in a MODE in which the RWST is not required. The short time limit of 1 hour to restore the RWST to OPERABLE status is based on this condition simultaneously affecting redundant trains.

C.1 and C.2

If the RWST cannot be returned to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.5.4.1

The RWST borated water temperature should be verified every 24 hours to be within the limits assumed in the accident analyses band. This Frequency is sufficient to identify a temperature change that would approach either limit and has been shown to be acceptable through operating experience.

The SR is modified by a Note that eliminates the requirement to perform this Surveillance unless ambient air temperatures are not within the operating limits of the RWST for more than 24 hours. With ambient air temperatures within the band, the RWST temperature should not exceed the limits.

SR 3.5.4.2

The RWST water volume should be verified every 7 days to be above the required minimum level in order to ensure that a sufficient initial supply is available for injection and to support continued ECCS System pump operation on recirculation. Since the RWST volume is normally stable and is protected by an alarm, a 7 day Frequency is appropriate and has been shown to be acceptable through operating experience.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.4.3

The boron concentration of the RWST should be verified every 31 days to be within the required limits. This SR ensures that the reactor will remain subcritical following a LOCA. Further, it assures that the resulting sump pH will be maintained in an acceptable range so that boron precipitation in the core will not occur and the effect of chloride and caustic stress corrosion on mechanical systems and components will be minimized. Since the RWST level is normally stable, a 31 day sampling Frequency to verify boron concentration is appropriate and has been shown to be acceptable through operating experience.

REFERENCES

1. FSAR, Chapter 6 and Chapter 14.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1 Containment

BASES

BACKGROUND

The containment consists of the concrete reactor building, its steel liner, and the penetrations through this structure. The structure is designed to contain radioactive material that may be released from the reactor core following a Design Basis Accident (DBA), in particular, a Main Steam Line Break (MSLB) inside containment or a Loss of Coolant Accident (LOCA). Additionally, this structure provides shielding from the fission products that may be present in the containment atmosphere following accident conditions.

The containment is a reinforced concrete structure with a cylindrical wall, a flat foundation mat, and a dome roof. The inside surface of the containment is lined with a carbon steel liner to ensure a high degree of leak tightness during operating and accident conditions.

The concrete reactor building is required for structural integrity of the containment under DBA conditions. The steel liner and its penetrations establish the leakage limiting boundary of the containment. Maintaining the containment OPERABLE limits the leakage of fission product radioactivity from the containment to the environment. SR 3.6.1.1 leakage rate requirements comply with 10 CFR 50, Appendix J, Option B, (Ref. 1), as established in Specification 5.5.15, Containment Leakage Rate Testing Program.

The isolation devices for the penetrations in the containment boundary are a part of the containment leak tight barrier. To maintain this leak tight barrier:

a. All penetrations required to be closed during accident conditions are either:

   1. capable of being closed by an OPERABLE automatic containment isolation system, or

BASES

BACKGROUND (Continued)

2. closed by manual valves, blind flanges, or de-activated automatic valves secured in their closed positions, except as provided in LCO 3.6.3, "Containment Isolation Valves";

b. Each air lock is OPERABLE, except as provided in LCO 3.6.2, "Containment Air Locks";

c. The equipment hatch is properly closed; and

d. The Isolation Valve Seal Water (IVSW) system is OPERABLE, except as provided in LCO 3.6.9.

APPLICABLE SAFETY ANALYSES

The safety design basis for the containment is that the containment must withstand the pressures and temperatures of the limiting DBA without exceeding the design leakage rate.

The DBAs that result in a challenge to containment OPERABILITY from high pressures and temperatures are a loss of coolant accident (LOCA) and a steam line break (Ref. 2). In addition, release of significant fission product radioactivity within containment can occur from a LOCA. In the DBA analyses, it is assumed that the containment is OPERABLE such that, for the DBAs involving release of fission product radioactivity, release to the environment is controlled by the rate of containment leakage. The containment was designed with an allowable leakage rate of 0.1% of containment air weight per day assuming the proper functioning of the Isolation Valve Seal Water System but without benefit of the Weld Channel and Penetration Pressurization System (Ref. 3). This leakage rate, used to evaluate offsite doses resulting from accidents, is defined in 10 CFR 50, Appendix J (Ref. 1), as L_a: the maximum allowable containment leakage rate at the calculated peak containment internal pressure (P_a) resulting from the limiting DBA. The allowable leakage rate represented by L_a forms the basis for the acceptance criteria imposed on all containment leakage rate testing. L_a is assumed

BASES

APPLICABLE SAFETY ANALYSES (continued)

to be 0.1% of containment air weight per day in the safety analysis at P_a which is specified in Specification 5.5.15, Containment Leakage Rate Testing Program.

Satisfactory leakage rate test results are a requirement for the establishment of containment OPERABILITY.

The containment satisfies Criterion 3 of 10 CFR 50.36.

LCO

Containment OPERABILITY is maintained by limiting leakage to $\leq 1.0\ L_a$, except prior to the first startup after performing a required 10 CFR 50, Appendix J, leakage test in accordance with requirements in Specification 5.5.15, Containment Leakage Rate Testing Program. At this time, the applicable leakage limits specified in the Containment Leakage Rate Testing Program must be met.

Compliance with this LCO will ensure a containment configuration, including the equipment hatch, that is structurally sound and that will limit leakage to less than the leakage rates assumed in the safety analysis.

Individual leakage rates specified for the containment air locks (LCO 3.6.2) are not specifically part of the acceptance criteria of 10 CFR 50, Appendix J, Option B. Therefore, leakage rates exceeding these individual limits only result in the containment being inoperable when the leakage results in exceeding the acceptance criteria of Appendix J.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material into containment. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, containment is not required to be OPERABLE in MODE 5 to prevent leakage of radioactive material from containment. The

BASES

APPLICABILITY (continued)

requirements for containment during MODE 6 are addressed in LCO 3.9.3, "Containment Penetrations."

ACTIONS

A.1

In the event containment is inoperable, containment must be restored to OPERABLE status within 1 hour. The 1 hour Completion Time provides a period of time to correct the problem commensurate with the importance of maintaining containment during MODES 1, 2, 3, and 4. This time period also ensures that the probability of an accident (requiring containment OPERABILITY) occurring during periods when containment is inoperable is minimal.

B.1 and B.2

If containment cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.1

Maintaining the containment OPERABLE requires compliance with the visual examinations and leakage rate test requirements of the Containment Leakage Rate Testing Program. Failure to meet air lock leakage limits specified in LCO 3.6.2 does not invalidate the acceptability of these overall leakage determinations unless their contribution to overall Type A, B, and C leakage causes that to exceed limits. As left leakage prior to the first

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.1 (continued)

startup after performing a required leakage test is required to be ≤ 0.6 L_a for combined Type B and C leakage following an outage or shutdown that included Type B and C testing only, and ≤ 0.75 L_a for overall Type A leakage following an outage or shutdown that included Type A testing. At all other times between required leakage rate tests, the acceptance criteria is based on an overall Type A leakage limit of ≤ 1.0 L_a. At ≤ 1.0 L_a the offsite dose consequences are bounded by the assumptions of the safety analysis. SR Frequencies are as required by the Containment Leakage Rate Testing Program. These periodic testing requirements verify that the containment leakage rate does not exceed the leakage rate assumed in the safety analysis.

REFERENCES

1. 10 CFR 50, Appendix J, Option B.
2. FSAR, Chapter 14.
3. FSAR, Section 6.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.2 Containment Air Locks

BASES

BACKGROUND

Containment air locks form part of the containment pressure boundary and provide a means for personnel access during all MODES of operation.

Each air lock is a cylinder with a door at each end. One of the two air locks is designed as a part of the containment structure and the other is designed as an integral part of the containment equipment hatch but otherwise the two air locks function identically. Each air lock door has been designed and tested to certify its ability to withstand a pressure in excess of the maximum expected pressure following a Design Basis Accident (DBA) in containment. As such, closure of a single door supports containment OPERABILITY.

Each air lock door and the equipment hatch is designed with double gasketed seals to permit pressurization between the gaskets. The double gasketed seals are normally continuously pressurized above accident pressure. Finally, to effect a leak tight seal, the air lock design uses pressure seated doors (i.e., an increase in containment internal pressure results in increased sealing force on each door) and local leakage rate testing capability is available to ensure containment integrity is being maintained.

The doors are interlocked to prevent simultaneous opening of the inner and outer door. This interlock is a requirement for OPERABILITY. During periods when containment is not required to be OPERABLE, the door interlock mechanism may be disabled, allowing both doors of an air lock to remain open for extended periods when frequent containment entry is necessary.

Each personnel air lock is provided with limit switches on both doors that provide control room indication when an airlock door is not fully closed.

The containment air locks form part of the containment pressure boundary. As such, air lock integrity and leak tightness is

BASES

BACKGROUND (continued)

essential for maintaining the containment leakage rate within limit in the event of a DBA. Not maintaining air lock integrity or leak tightness may result in a leakage rate in excess of that assumed in the unit safety analyses.

APPLICABLE SAFETY ANALYSES

The DBAs that result in a release of radioactive material within containment are a loss of coolant accident and a rod ejection accident. In the analysis of each of these accidents, it is assumed that containment is OPERABLE such that release of fission products to the environment is controlled by the rate of containment leakage. The containment was designed with an allowable leakage rate of 0.1% of containment air weight per day (Ref. 2). This leakage rate is defined in 10 CFR 50, Appendix J (Ref. 1), as L_a = 0.1% of containment air weight per day, the maximum allowable containment leakage rate at the calculated peak containment internal pressure following a DBA. The peak pressure following a DBA is specified in Specification 5.5.15, Containment Leakage Rate Testing Program. This allowable leakage rate forms the basis for the acceptance criteria imposed on the SRs associated with the air locks.

The containment air locks satisfy Criterion 3 of 10 CFR 50.36.

LCO

Each containment air lock forms part of the containment pressure boundary. As part of containment, the air lock safety function is related to control of the containment leakage rate resulting from a DBA. Thus, each air lock's structural integrity and leak tightness are essential to the successful mitigation of such an event.

Each air lock is required to be OPERABLE. For the air lock to be considered OPERABLE, the air lock interlock mechanism must be OPERABLE, the air lock must be in compliance with the Type B air lock leakage test, and both air lock doors must be OPERABLE. The

BASES

LCO (continued)

interlock allows only one air lock door of an air lock to be opened at one time. This provision ensures that a gross breach of containment does not exist when containment is required to be OPERABLE. Closure of a single door in each air lock is sufficient to provide a leak tight barrier following postulated events. Nevertheless, both doors are kept closed when the air lock is not being used for normal entry into or exit from containment.

Pressurization of air lock seals is not required for air lock OPERABILITY. However, 10 CFR 50, Appendix J, Section III.2.b(iii), specifies that air locks opened during periods when containment integrity is required must be tested within 3 days after being opened. However, for air lock doors having testable seals, testing the seals (i.e., verification that seals re-pressurize to the required pressure after an air lock door is closed) fulfills the 3-day test requirements. Therefore, the status of air lock seals has the potential to affect air lock OPERABILITY.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, the containment air locks are not required in MODE 5 to prevent leakage of radioactive material from containment. The requirements for the containment air locks during MODE 6 are addressed in LCO 3.9.3, "Containment Penetrations."

ACTIONS

The ACTIONS are modified by a Note that allows entry and exit to perform repairs on the affected air lock component. If the outer door is inoperable, then it may be easily accessed for most repairs. When the inner door is inoperable, it is preferred that the air lock be accessed from inside primary containment by entering through the other OPERABLE air lock. However, if this is not practicable, or if repairs on either door must be

BASES

ACTIONS (continued)

performed from the barrel side of the door then it is permissible to enter the air lock through the OPERABLE door, which means there is a short time during which the containment boundary is not intact (during access through the OPERABLE door). The ability to open the OPERABLE door, even if it means the containment boundary is temporarily not intact, is acceptable due to the low probability of an event that could pressurize the containment during the short time in which the OPERABLE door is expected to be open. After each entry and exit, the OPERABLE door must be immediately closed. If ALARA conditions permit, entry and exit should be via an OPERABLE air lock.

A second Note has been added to provide clarification that, for this LCO, separate Condition entry is allowed for each air lock. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable air lock. Complying with the Required Actions may allow for continued operation, and a subsequent inoperable air lock is governed by subsequent Condition entry and application of associated Required Actions.

In the event the air lock leakage results in exceeding the overall containment leakage rate, Note 3 directs entry into the applicable Conditions and Required Actions of LCO 3.6.1, "Containment."

<u>A.1, A.2, and A.3</u>

With one air lock door in one or more containment air locks inoperable, the OPERABLE door must be verified closed (Required Action A.1) in each affected containment air lock. This ensures that a leak tight containment barrier is maintained by the use of an OPERABLE air lock door. This action must be completed within 1 hour. This specified time period is consistent with the ACTIONS of LCO 3.6.1, which requires containment be restored to OPERABLE status within 1 hour.

In addition, the affected air lock penetration must be isolated by locking closed the OPERABLE air lock door within the 24 hour Completion Time. The 24 hour Completion Time is reasonable for

BASES

ACTIONS

A.1. A.2. and A.3 (continued)

locking the OPERABLE air lock door, considering the OPERABLE door of the affected air lock is being maintained closed.

Required Action A.3 verifies that an air lock with an inoperable door has been isolated by the use of a locked and closed OPERABLE air lock door. This ensures that an acceptable containment leakage boundary is maintained. The Completion Time of once per 31 days is based on engineering judgment and is considered adequate in view of the low likelihood of a locked door being mispositioned and other administrative controls. Required Action A.3 is modified by a Note that applies to air lock doors located in high radiation areas and allows these doors to be verified locked closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment of the door, once it has been verified to be in the proper position, is small.

The Required Actions have been modified by two Notes. Note 1 ensures that only the Required Actions and associated Completion Times of Condition C are required if both doors in the same air lock are inoperable. With both doors in the same air lock inoperable, an OPERABLE door is not available to be closed. Required Actions C.1 and C.2 are the appropriate remedial actions. The exception of Note 1 does not affect tracking the Completion Time from the initial entry into Condition A; only the requirement to comply with the Required Actions. Note 2 allows use of the air lock for entry and exit for 7 days under administrative controls if both air locks have an inoperable door. This 7 day restriction begins when the second air lock is discovered inoperable. Containment entry may be required on a periodic basis to perform Technical Specifications (TS) Surveillances and Required Actions, as well as other activities on equipment inside containment that are required by TS or activities on equipment that support TS-required equipment. This Note is not intended to preclude performing other activities (i.e., non-TS-required activities) if the containment is entered, using the inoperable air lock, to perform an allowed activity listed above. This allowance is acceptable due to the low probability of an event that could pressurize the containment

BASES

ACTIONS

A.1. A.2. and A.3 (continued)

during the short time that the OPERABLE door is expected to be open.

B.1. B.2. and B.3

With an air lock interlock mechanism inoperable in one or more air locks, the Required Actions and associated Completion Times are consistent with those specified in Condition A.

The Required Actions have been modified by two Notes. Note 1 ensures that only the Required Actions and associated Completion Times of Condition C are required if both doors in the same air lock are inoperable. With both doors in the same air lock inoperable, an OPERABLE door is not available to be closed. Required Actions C.1 and C.2 are the appropriate remedial actions. Note 2 allows entry into and exit from containment under the control of a dedicated individual stationed at the air lock to ensure that only one door is opened at a time (i.e., the individual performs the function of the interlock).

Required Action B.3 is modified by a Note that applies to air lock doors located in high radiation areas and allows these doors to be verified locked closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment of the door, once it has been verified to be in the proper position, is small.

C.1. C.2. and C.3

With one or more air locks inoperable for reasons other than those described in Condition A or B, Required Action C.1 requires action to be initiated immediately to evaluate previous combined leakage rates using current air lock test results. An evaluation is acceptable, since it is overly conservative to immediately declare the containment inoperable if both doors in an air lock have failed a seal test or if the overall air lock leakage is not within limits. In many instances (e.g., only one seal per door has failed), containment remains OPERABLE, yet only 1 hour (per LCO 3.6.1) would be provided to restore the air lock door to

BASES

ACTIONS

C.1, C.2, and C.3 (continued)

OPERABLE status prior to requiring a plant shutdown. In addition, even with both doors failing the seal test, the overall containment leakage rate can still be within limits.

Required Action C.2 requires that one door in the affected containment air lock must be verified to be closed within the 1 hour Completion Time. This specified time period is consistent with the ACTIONS of LCO 3.6.1, which requires that containment be restored to OPERABLE status within 1 hour.

Additionally, the affected air lock(s) must be restored to OPERABLE status within the 24 hour Completion Time unless Condition C is exited in accordance with LCO 3.0.2 (i.e., one door OPERABLE). The specified time period is considered reasonable for restoring an inoperable air lock to OPERABLE status, assuming that at least one door is maintained closed in each affected air lock.

D.1 and D.2

If the inoperable containment air lock cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.2.1

Maintaining containment air locks OPERABLE requires compliance with the leakage rate test requirements of 10 CFR 50, Appendix J (Ref. 1), in accordance with Specification 5.5.15, Containment Leakage Rate Testing Program. This SR reflects the leakage rate testing requirements with regard to air lock leakage (Type B leakage tests). The acceptance criteria were established during

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.2.1 (continued)

initial air lock and containment OPERABILITY testing. The periodic testing requirements verify that the air lock leakage does not exceed the allowed fraction of the overall containment leakage rate. The Frequency is in accordance with Specification 5.5.15, Containment Leakage Rate Testing Program.

The SR has been modified by two Notes. Note 1 states that an inoperable air lock door does not invalidate the previous successful performance of the overall air lock leakage test. This is considered reasonable since either air lock door is capable of providing a fission product barrier in the event of a DBA. Note 2 has been added to this SR requiring the results to be evaluated against the acceptance criteria that is applicable to SR 3.6.1.1. This ensures that air lock leakage is properly accounted for in determining the combined Type B and C containment leakage rate.

SR 3.6.2.2

The air lock interlock is designed to prevent simultaneous opening of both doors in a single air lock. Since both the inner and outer doors of an air lock are designed to withstand the maximum expected post accident containment pressure, closure of either door will support containment OPERABILITY. Thus, the door interlock feature supports containment OPERABILITY while the air lock is being used for personnel transit in and out of the containment. Periodic testing of this interlock demonstrates that the interlock will function as designed and that simultaneous opening of the inner and outer doors will not inadvertently occur. Due to the purely mechanical nature of this interlock, and given that the interlock mechanism is not normally challenged when the containment air lock door is used for entry and exit, this test is only required to be performed every 24 months. The 24 month Frequency is based on the need to perform this Surveillance under conditions that apply during a plant outage, and the potential for loss of containment OPERABILITY if

BASES
SURVEILLANCE REQUIREMENTS

SR 3.6.2.2 (continued)

the Surveillance were performed with the reactor at power. The 24 month Frequency for the interlock is justified based on generic operating experience. The Frequency is based on engineering judgment and is considered adequate given that the interlock is not normally challenged during the use of the airlock.

REFERENCES

1. 10 CFR 50, Appendix J.
2. FSAR, Section 6.6.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.3 Containment Isolation Valves

BASES

BACKGROUND

The containment isolation valves form part of the containment pressure boundary and provide a means for fluid penetrations not serving accident consequence limiting systems to be provided with two isolation barriers that are closed on a containment isolation signal. These isolation devices are either passive or active (automatic). Manual valves, de-activated automatic valves secured in their closed position (including check valves with flow through the valve secured), blind flanges, and closed systems are considered passive devices. Check valves, or other automatic valves designed to close without operator action following an accident, are considered active devices. Two barriers in series are provided for each penetration so that no single credible failure or malfunction of an active component can result in a loss of isolation or leakage that exceeds limits assumed in the safety analyses. One of these barriers may be a closed system. These barriers (typically containment isolation valves) make up the Containment Isolation System.

Automatic isolation signals are produced during accident conditions. Containment Phase "A" isolation occurs upon receipt of a safety injection signal. The Phase "A" isolation signal isolates nonessential process lines in order to minimize leakage of fission product radioactivity. Containment Phase "B" isolation occurs upon receipt of a containment pressure High-High signal and isolates the remaining process lines, except systems required for accident mitigation. In addition to the isolation signals listed above, the containment purge supply and exhaust isolation valves (FCV-1170, FCV-1171, FCV-1172, and FCV-1173) and the containment pressure relief isolation valves (PCV-1190, PCV-1191, and PCV-1192) close when high radiation levels are detected by the Containment Air Particulate Monitor (R-11) or Containment Radioactive Gas Monitor (R-12). Containment purge and containment pressure relief are also isolated when high radiation levels are detected in the plant vent. As a result, the containment isolation valves (and blind flanges) help ensure that the containment atmosphere will be isolated from the environment

BASES

BACKGROUND (Continued)

in the event of a release of fission product radioactivity to the containment atmosphere as a result of a Design Basis Accident (DBA).

The OPERABILITY requirements for containment isolation valves help ensure that containment is isolated within the time limits assumed in the safety analyses. Therefore, the OPERABILITY requirements provide assurance that the containment function assumed in the safety analyses will be maintained.

Containment Purge System (36 inch purge valves)

The Containment Purge System, consisting of purge supply and exhaust isolation valves FCV-1170, FCV-1171, FCV-1172, and FCV-1173, operates to supply outside air into the containment for ventilation and cooling or heating and may also be used to reduce the concentration of noble gases within containment prior to and during personnel access. The supply and exhaust lines each contain two isolation valves. Because of their large size, the 36 inch purge valves are not qualified for automatic closure from their open position under DBA conditions. Therefore, the 36 inch purge valves must be maintained sealed closed in MODES 1, 2, 3, and 4 to ensure the containment boundary is maintained.

Containment Pressure Relief Line (10 inch valves)

The Containment Pressure Relief Line consisting of pressure relief isolation valves PCV-1190, PCV-1191, and PCV-1192, operates to:

a. Reduce the concentration of noble gases within containment prior to and during personnel access, and

b. Equalize internal and external pressures.

Since the valves used in the Containment Pressure Relief Line System are designed to meet the requirements for automatic containment isolation valves, these valves may be opened as needed in MODES 1, 2, 3, and 4. Containment pressure relief line isolation valve opening is limited by mechanical stops so that

BASES

BACKGROUND (Continued)

opening angle is limited to an angle at which analysis indicates the valve will operate against containment accident pressures. Additionally, pressure relief isolation valve opening must be limited to the time necessary for pressure control, ALARA or air quality considerations for personnel entry, or for Surveillances that require the valves to be open.

The containment pressure relief line is isolated during CORE ALTERATIONS and movement of irradiated fuel inside containment in accordance with requirements established in LCO 3.9.3, Containment Penetrations.

APPLICABLE SAFETY ANALYSES

The containment isolation valve LCO was derived from the assumptions related to minimizing the loss of reactor coolant inventory and establishing the containment boundary during major accidents. As part of the containment boundary, containment isolation valve OPERABILITY supports leak tightness of the containment. Therefore, the safety analyses of any event requiring isolation of containment is applicable to this LCO.

The DBA that results in a release of radioactive material within containment is a loss of coolant accident (LOCA) (Ref. 1). In the analyses for each of these accidents, it is assumed that containment isolation valves are either closed or function to close within the required isolation time following event initiation. This ensures that potential paths to the environment through containment isolation valves are minimized. The safety analyses assume that the 36 inch purge valves are sealed closed at event initiation.

The DBA analysis assumes that, within 60 seconds after the accident, isolation of the containment is complete and leakage terminated except for the design leakage rate, L_a. The containment isolation total response time of 60 seconds includes signal delay, diesel generator startup (for loss of offsite power), and containment isolation valve stroke times.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The containment purge supply and exhaust isolation valves (FCV-1170, FCV-1171, FCV-1172, and FCV-1173) may be unable to close in the environment following a LOCA. Therefore, each of the purge valves is required to remain sealed closed during MODES 1, 2, 3, and 4. In this case, the single failure criterion remains applicable to the containment purge valves due to failure in the control circuit associated with each valve. Again, the purge system valve design precludes a single failure from compromising the containment boundary as long as the system is operated in accordance with the subject LCO.

The term sealed closed, as applied to containment isolation valves, is not intended to describe leak tightness. Sealed closed isolation valves must be under administrative controls that assure the valve cannot be inadvertently opened. Administrative controls includes mechanical devices to seal or lock the valve closed, or to prevent power from being supplied to the valve operator (Ref. 3). Sealed closed barriers include blind flanges and sealed closed isolation valves including closed manual valves, closed remote-manual valves, and closed automatic valves which remain closed after a loss-of-coolant accident. Sealed closed barriers may be used in place of any automatic isolation valve.

The containment isolation valves satisfy Criterion 3 of 10 CFR 50.36.

LCO

Containment isolation valves form a part of the containment boundary. The containment isolation valves' safety function is related to minimizing the loss of reactor coolant inventory and establishing the containment boundary during a DBA.

The automatic power operated isolation valves are required to have isolation times within limits and to actuate on an automatic isolation signal. The 36 inch purge valves must be maintained sealed closed.

BASES

LCO (continued)

The valves covered by this LCO are listed in the FSAR (Ref. 2). The normally closed isolation valves are considered OPERABLE when manual valves are closed, automatic valves are de-activated and secured in their closed position, blind flanges are in place, and closed systems are intact (Ref. 3).

Manually operated containment isolation valves on essential lines that are required to be open, at least for a time, during post accident conditions are OPERABLE if they can be closed in accordance with design assumptions. Essential lines are those lines required to mitigate an accident, or which, if unavailable, could increase the magnitude of the event. Also, those lines which, if available, would be used in the short term (24 to 36 hours) to restore the plant to normal operation following an event which has resulted in containment isolation (Ref. 4).

This LCO provides assurance that the containment isolation valves and purge valves will perform their designed safety functions to minimize the loss of reactor coolant inventory and establish the containment boundary during accidents.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, the containment isolation valves are not required to be OPERABLE in MODE 5. The requirements for containment isolation valves during MODE 6 are addressed in LCO 3.9.3, Containment Penetrations.

ACTIONS

The ACTIONS are modified by Note 1, which allows penetration flow paths that are isolated in accordance with Required Actions, except for 36 inch purge valve penetration flow paths, to be unisolated intermittently under administrative controls. These administrative controls consist of stationing a dedicated operator at the valve controls, who is in continuous

BASES

ACTIONS (continued)

communication with the control room. In this way, the penetration can be rapidly isolated when a need for containment isolation is indicated. Due to the size of the containment purge line penetration and the fact that those penetrations exhaust from the containment atmosphere to the environment, the penetration flow path containing these valves may not be opened under administrative controls.

Note 2 has been added to provide clarification that, for this LCO, separate Condition entry is allowed for each penetration flow path. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable containment isolation valve. Complying with the Required Actions may allow for continued operation, and subsequent inoperable containment isolation valves are governed by subsequent Condition entry and application of associated Required Actions.

The ACTIONS are further modified by Note 3, which ensures appropriate remedial actions are taken if the affected systems are rendered inoperable by an inoperable containment isolation valve.

In the event containment isolation valve leakage results in exceeding the overall containment leakage rate, Note 4 directs entry into the applicable Conditions and Required Actions of LCO 3.6.1.

The ACTIONS are further modified by Note 5, which ensures appropriate remedial actions are taken if required IVSW supply to a penetration flowpath is inoperable. Specifically, Note 5 directs entry into the applicable Conditions and Required Actions of LCO 3.6.9.

<u>A.1 and A.2</u>

In the event one containment isolation valve in one or more penetration flow paths is inoperable, the affected penetration flow path must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be

BASES

ACTIONS

A.1 and A.2 (continued)

adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic containment isolation valve, a closed manual valve, a blind flange, and a check valve with flow through the valve secured (Ref. 3). For a penetration flow path isolated in accordance with Required Action A.1, the device used to isolate the penetration should be the closest available one to containment. Required Action A.1 must be completed within 4 hours. The 4 hour Completion Time is reasonable, considering the time required to isolate the penetration and the relative importance of supporting containment OPERABILITY during MODES 1, 2, 3, and 4.

For affected penetration flow paths that cannot be restored to OPERABLE status within the 4 hour Completion Time and that have been isolated in accordance with Required Action A.1, the affected penetration flow paths must be verified to be isolated on a periodic basis. This is necessary to ensure that containment penetrations required to be isolated following an accident and no longer capable of being automatically isolated will be in the isolation position should an event occur. This Required Action does not require any testing or device manipulation. This action involves verification, through a system walkdown, that isolation devices outside containment and capable of being mispositioned are in the correct position. The Completion Time of "once per 31 days for isolation devices outside containment" is appropriate considering the fact that the devices are operated under administrative controls and the probability of their misalignment is low. For the isolation devices inside containment e.g., one of the three containment pressure relief isolation valves, the time period specified as "prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days" is based on engineering judgment and is considered reasonable in view of the inaccessibility of the isolation devices and other administrative controls that will ensure that isolation device misalignment is an unlikely possibility.

Condition A has been modified by a Note indicating that this Condition is only applicable to those penetration flow paths with

BASES

ACTIONS

A.1 and A.2 (continued)

two or more containment isolation valves. Although most penetrations have two containment isolation valves, the term "two or more" is used so that Condition A includes the pressure relief line penetration which has three valves in series. For penetration flow paths with only one containment isolation valve and a closed system, Condition C provides the appropriate actions.

Required Action A.2 is modified by a Note that applies to isolation devices located in high radiation areas and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment of these devices once they have been verified to be in the proper position, is small.

B.1

With two containment isolation valves in one or more penetration flow paths inoperable, the affected penetration flow path must be isolated within 1 hour. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, and a blind flange. The 1 hour Completion Time is consistent with the ACTIONS of LCO 3.6.1. In the event the affected penetration is isolated in accordance with Required Action B.1, the affected penetration must be verified to be isolated on a periodic basis per Required Action A.2, which remains in effect. This periodic verification is necessary to assure leak tightness of containment and that penetrations requiring isolation following an accident are isolated. The Completion Time of once per 31 days for verifying each affected penetration flow path is isolated is appropriate considering the fact that the valves are operated under administrative control and the probability of their misalignment is low.

Condition B is modified by a Note indicating this Condition is only applicable to penetration flow paths with two containment

BASES

ACTIONS

B.1 (continued)

isolation valves. Although most penetrations have two containment isolation valves, the term "two or more" is used so that Condition B includes the pressure relief line penetration which has three valves in series. Condition A of this LCO addresses the condition of one containment isolation valve inoperable in this type of penetration flow path.

C.1 and C.2

With one or more penetration flow paths with one containment isolation valve inoperable, the inoperable valve flow path must be restored to OPERABLE status or the affected penetration flow path must be isolated. The method of isolation must include the use of at least one isolation barrier, other than the closed system that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, and a blind flange (Ref. 3). A check valve may not be used to isolate the affected penetration flow path. Required Action C.1 must be completed within the 72 hour Completion Time. The specified time period is reasonable considering the relative stability of the closed system (hence, reliability) to act as a penetration isolation boundary and the relative importance of maintaining containment integrity during MODES 1, 2, 3, and 4. In the event the affected penetration flow path is isolated in accordance with Required Action C.1, the affected penetration flow path must be verified to be isolated on a periodic basis. This periodic verification is necessary to assure leak tightness of containment and that containment penetrations requiring isolation following an accident are isolated. The Completion Time of once per 31 days for verifying that each affected penetration flow path is isolated is appropriate because the valves are operated under administrative controls and the probability of their misalignment is low.

Condition C is modified by a Note indicating that this Condition is only applicable to those penetration flow paths with only one containment isolation valve and a closed system. This Note is necessary since this Condition is written to specifically address those penetration flow paths in a closed system.

BASES

ACTIONS

C.1 and C.2 (continued)

Required Action C.2 is modified by a Note that applies to valves and blind flanges located in high radiation areas and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment of these valves, once they have been verified to be in the proper position, is small.

D.1 and D.2

If the Required Actions and associated Completion Times are not met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.3.1

Each 36 inch containment purge supply and exhaust isolation valve (FCV-1170, FCV-1171, FCV-1172, and FCV-1173) is required to be verified sealed closed at 31 day intervals. This Surveillance is designed to ensure that a gross breach of containment is not caused by an inadvertent or spurious opening of a containment purge valve. Detailed analysis of the purge valves failed to conclusively demonstrate their ability to close during a LOCA in time to limit offsite doses. Therefore, these valves are required to be in the sealed closed position during MODES 1, 2, 3, and 4. The term sealed closed, as applied to containment isolation valves, is not intended to describe leak tightness. Sealed closed isolation valves must be under administrative controls that assure the valve cannot be inadvertently opened. Administrative controls includes mechanical devices to seal or

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.3.1 (continued)

lock the valve closed, or to prevent power from being supplied to the valve operator (Ref. 3). Sealed closed barriers include blind flanges and sealed closed isolation valves including closed manual valves, closed remote-manual valves, and closed automatic valves which remain closed after a loss-of-coolant accident.

The Frequency is a result of an NRC initiative, Generic Issue B-24 (Ref. 5), related to containment purge valve use during plant operations.

SR 3.6.3.2

This SR ensures that the containment pressure relief line isolation valves (PCV-1190, PCV-1191, and PCV-1192) are closed as required or, if open, open for an allowable reason. If a containment pressure relief line isolation valve is open in violation of this SR, the valve is considered inoperable. If the inoperable valve is not otherwise known to have excessive leakage when closed, it is not considered to have leakage outside of limits. The SR is not required to be met when the containment pressure relief line isolation valves are open for the reasons stated. The valves may be opened for pressure control, ALARA or air quality considerations for personnel entry, or for Surveillances that require the valves to be open. The containment pressure relief line isolation valves are capable of closing in the environment following a LOCA as long as valve opening angle is limited in accordance with SR 3.6.3.7. Therefore, these valves are allowed to be open for limited periods of time. The 31 day Frequency is consistent with other containment isolation valve requirements discussed in SR 3.6.3.3.

SR 3.6.3.3

This SR requires verification that each containment isolation manual valve and blind flange located outside containment and not locked, sealed, or otherwise secured and required to be closed during accident conditions is closed. The SR helps to ensure that post accident leakage of radioactive fluids or gases outside

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.3.3 (continued)

of the containment boundary is within design limits. This SR does not require any testing or valve manipulation. Rather, it involves verification, through a system walkdown, that those containment isolation valves outside containment and capable of being mispositioned are in the correct position. Since verification of valve position for containment isolation valves outside containment is relatively easy, the 31 day Frequency is based on engineering judgment and was chosen to provide added assurance of the correct positions. The SR specifies that containment isolation valves that are open under administrative controls are not required to meet the SR during the time the valves are open. This SR does not apply to valves that are locked, sealed or otherwise secured in the closed position because these valves were verified to be in the correct position when locked, sealed or otherwise secured.

The Note applies to valves and blind flanges located in high radiation areas and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted during MODES 1, 2, 3 and 4 for ALARA reasons. Therefore, the probability of misalignment of these containment isolation valves, once they have been verified to be in the proper position, is small.

SR 3.6.3.4

This SR requires verification that each containment isolation manual valve and blind flange located inside containment and not locked, sealed, or otherwise secured and required to be closed during accident conditions is closed. The SR helps to ensure that post accident leakage of radioactive fluids or gases outside of the containment boundary is within design limits. For containment isolation valves inside containment, the Frequency of "prior to entering MODE 4 from MODE 5 if not performed within the previous 92 days" is appropriate since these containment isolation valves are operated under administrative controls and the probability of their misalignment is low. The SR specifies

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.3.4 (continued)

that containment isolation valves that are open under administrative controls are not required to meet the SR during the time they are open. This SR does not apply to valves that are locked, sealed or otherwise secured in the closed position because these valves were verified to be in the correct position when locked sealed or otherwise secured.

This Note allows valves and blind flanges located in high radiation areas to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted during MODES 1, 2, 3, and 4, for ALARA reasons. Therefore, the probability of misalignment of these containment isolation valves, once they have been verified to be in their proper position, is small.

SR 3.6.3.5

Verifying that the isolation time of each automatic power operated containment isolation valve is within limits is required to demonstrate OPERABILITY. The isolation time test ensures the valve will isolate in a time period less than or equal to that assumed in the safety analyses as specified in the FSAR. The isolation time and Frequency of this SR are in accordance with the Inservice Testing Program.

SR 3.6.3.6

Automatic power operated containment isolation valves close on a containment isolation signal to prevent leakage of radioactive material from containment following a DBA. This SR ensures that each automatic containment isolation valve will actuate to its isolation position on a containment isolation signal. This surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.3.6 (continued)

transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass this Surveillance when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.6.3.7

Verifying that each containment pressure relief line isolation valve, PCV-1190, PCV-1191, and PCV-1192, is blocked to restrict valve opening to ≤ 60 degrees. This verification is required to ensure that the valves can close under DBA conditions within the times assumed in the analyses of References 1 and 2. If a LOCA occurs, the pressure releif line valves must close to maintain containment leakage within the values assumed in the accident analysis. The 24 month Frequency is appropriate because the blocking devices can be removed only when plant is in MODE 5 or 6.

SR 3.6.3.8

This SR ensures that the combined leakage rate of all containment leakage paths is less than or equal to the specified leakage rate for those paths that are not sealed by the Isolation Valve Seal Water System or sealed by the RHR system or sealed by the service water system. This provides assurance that the assumptions in the safety analysis are met. The leakage rate of each bypass leakage path is assumed to be the maximum pathway leakage (leakage through the worse of the two isolation valves) unless the penetration is isolated by use of one closed and de-activated automatic valve, closed manual valve, or blind flange. In this case, the leakage rate of the isolated bypass leakage path is assumed to be the actual pathway leakage through the isolation device. If both isolation valves in the penetration are closed, the actual leakage rate is the lesser leakage rate of the two valves.

BASES

SURVEILLANCE REQUIRMENTS

SR 3.6.3.8 (continued)

This testing is performed in accordance with the requirements, Frequency and acceptance criteria established in Specification 5.5.15, Containment Leakage Rate Testing Program. This program was established to implement the leakage rate testing of the containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B, as modified by IP3 specific approved exemptions. This program conforms to guidelines contained in Regulatory Guide 1.163, "Performance-Based Containment Leak Test Program, dated September 1995." In the event containment isolation valve leakage results in exceeding the overall containment leakage rate, entry into the applicable Conditions and Required Actions of LCO 3.6.1 is required.

REFERENCES

1. FSAR, Section 14.
2. FSAR, Section 6.
3. Standard Review Plan Section 6.2.4, Item II.3.f.
4. FSAR, Section 5.2.
5. Generic Issue B-24.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.4 Containment Pressure

BASES

BACKGROUND

The containment pressure is limited during normal operation to preserve the initial conditions assumed in the accident analyses for a loss of coolant accident (LOCA) or steam line break (SLB). The containment can withstand an internal vacuum of 3 psig. The 2.0 psig vacuum specified as an operating limit avoids any difficulties with motor cooling.

Containment pressure is a process variable that is monitored and controlled. The containment pressure limits are derived from the input conditions used in the containment functional analyses and the containment structure external pressure analysis. Should operation occur outside these limits coincident with a Design Basis Accident (DBA), post accident containment pressures could exceed calculated values.

APPLICABLE SAFETY ANALYSES

Containment internal pressure is an initial condition used in the DBA analyses to establish the maximum peak containment internal pressure. The limiting DBAs considered, relative to containment pressure, are the LOCA and SLB, which are analyzed using computer pressure transients. Cycle specific analysis results indicate that the worst case peak containment pressure could result from either a loss of coolant accident or a steam line break inside containment (Ref. 1).

The initial pressure condition used in the containment analysis was +2.5 psig. This analysis concluded that the containment design pressure of 47 psig would not be exceeded for either a major loss-of-coolant accident or for a main steam line break accident. The containment analysis results are presented in Reference 1 and the current value for peak containment pressure is listed in Specification 5.5.15, "Containment Leakage Rate Testing Program."

BASES

APPLICABLE SAFETY ANALYSES (continued)

The containment was also designed for an external pressure load equivalent to -3.0 psig (i.e., the containment can withstand an internal vacuum of 3 psig). The -2.0 psig specified as the Limiting Condition for Operation is based on limits associated with motor cooling.

For certain aspects of transient accident analyses, maximizing the calculated containment pressure is not conservative. In particular, the cooling effectiveness of the Emergency Core Cooling System during the core reflood phase of a LOCA analysis increases with increasing containment backpressure. Therefore, for the reflood phase, the containment backpressure is calculated in a manner designed to conservatively minimize, rather than maximize, the containment pressure response in accordance with 10 CFR 50, Appendix K (Ref. 2).

Containment pressure satisfies Criterion 2 of 10 CFR 50.36.

LCO

Maintaining containment pressure at less than or equal to the LCO upper pressure limit ensures that, in the event of a DBA, the resultant peak containment accident pressure will remain below the containment design pressure. Maintaining containment pressure at greater than or equal to the LCO lower pressure limit ensures that motor heating concerns are addressed.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment. Since maintaining containment pressure within limits is essential to ensure initial conditions assumed in the accident analyses are maintained, the LCO is applicable in MODES 1, 2, 3 and 4.

In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, maintaining containment pressure within the limits of the LCO is not required in MODE 5 or 6.

BASES

ACTIONS

A.1

When containment pressure is not within the limits of the LCO, it must be restored to within these limits within 1 hour. The Required Action is necessary to return operation to within the bounds of the containment analysis. The 1 hour Completion Time is consistent with the ACTIONS of LCO 3.6.1, "Containment," which requires that containment be restored to OPERABLE status within 1 hour.

B.1 and B.2

If containment pressure cannot be restored to within limits within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.4.1

Verifying that containment pressure is within limits ensures that unit operation remains within the limits assumed in the containment analysis. The 12 hour Frequency of this SR was developed based on operating experience related to trending of containment pressure variations during the applicable MODES. Furthermore, the 12 hour Frequency is considered adequate in view of other indications available in the control room, including alarms, to alert the operator to an abnormal containment pressure condition.

BASES

REFERENCES

1. FSAR, Section 14.3
2. 10 CFR 50, Appendix K.
3. FSAR Section 3.1.8, Appendix 5A.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.5 Containment Air Temperature

BASES

BACKGROUND

The containment structure serves to contain radioactive material that may be released from the reactor core following a Design Basis Accident (DBA). The containment average air temperature is limited during normal operation to preserve the initial conditions assumed in the accident analyses for a loss of coolant accident (LOCA) or steam line break (SLB).

The containment average air temperature limit is derived from the input conditions used in the containment functional analyses and the containment structure external pressure analyses. This LCO ensures that initial conditions assumed in the analysis of containment response to a DBA are not violated during unit operations. The total amount of energy to be removed from containment by the Containment Spray and Cooling systems during post accident conditions is dependent upon the energy released to the containment due to the event, as well as the initial containment temperature and pressure. The higher the initial temperature, the more energy that must be removed, resulting in higher peak containment pressure and temperature. Exceeding containment design pressure may result in leakage greater than that assumed in the accident analysis. Operation with containment temperature in excess of the LCO limit violates an initial condition assumed in the accident analysis.

APPLICABLE SAFETY ANALYSES

Containment average air temperature is an initial condition used in the DBA analyses that establishes the containment environmental qualification operating envelope for both pressure and temperature. The limit for containment average air temperature ensures that operation is maintained within the assumptions used in the DBA analyses for containment (Ref. 1).

The limiting DBAs considered relative to containment OPERABILITY are the LOCA and SLB. The DBA LOCA and SLB are analyzed using computer codes designed to predict the resultant containment

BASES

APPLICABLE SAFETY ANALYSES (continued)

pressure transients. No two DBAs are assumed to occur simultaneously or consecutively. The postulated DBAs are analyzed with regard to Engineered Safety Feature (ESF) systems, assuming the loss of one ESF bus, which is the worst case single active failure, resulting in one train each of the Containment Spray System, Residual Heat Removal System, and Containment Cooling System being rendered inoperable.

The limiting DBA for the maximum peak containment air temperature may be either a LOCA or a SLB. The initial containment average air temperature is assumed in the design basis analyses. The maximum containment air temperature and the design temperature are specified in (Ref. 1.)

The temperature limit is used to establish the environmental qualification operating envelope for containment. The maximum peak containment air temperature was calculated to exceed the containment design temperature for only a few seconds during the transient. The basis of the containment design temperature, however, is to ensure the performance of safety related equipment inside containment (Ref. 2). Thermal analyses showed that the time interval during which the containment air temperature exceeded the containment design temperature was short enough that the equipment surface temperatures remained below the design temperature. Therefore, it is concluded that the calculated transient containment air temperature is acceptable for the DBA LOCA or SLB.

The containment pressure transient is sensitive to the initial air mass in containment and, therefore, to the initial containment air temperature. The limiting DBA for establishing the maximum peak containment internal pressure may be either a LOCA or a SLB. The temperature limit is used in this analysis to ensure that in the event of an accident the maximum containment internal pressure will not be exceeded.

Containment average air temperature satisfies Criterion 2 of 10 CFR 50.36.

BASES

LCO

During a DBA, with an initial containment average air temperature less than or equal to the LCO temperature limit, the resultant peak accident temperature is maintained below the containment design temperature. As a result, the ability of containment to perform its design function is ensured.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, maintaining containment average air temperature within the limit is not required in MODE 5 or 6.

ACTIONS

A.1

When containment average air temperature is not within the limit of the LCO, it must be restored to within limit within 8 hours. This Required Action is necessary to return operation to within the bounds of the containment analysis. The 8 hour Completion Time is acceptable considering the sensitivity of the analysis to variations in this parameter and provides sufficient time to correct minor problems.

B.1 and B.2

If the containment average air temperature cannot be restored to within its limit within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.5.1

Verifying that containment average air temperature is within the LCO limit ensures that containment operation remains within the limit assumed for the containment analyses. In order to determine the containment average air temperature, an arithmetic average is calculated using measurements taken at locations within the containment selected to provide a representative sample of the overall containment atmosphere.

A representative measurement of containment air temperature requires an arithmetic average of temperatures measured at no fewer than 4 locations. Environmentally and seismically qualified RTDs mounted on the crane wall above the containment fan cooler units inlet are normally used for measuring containment ambient temperature. Portable temperature sensing equipment may also be used.

The 24 hour Frequency of this SR is considered acceptable based on observed slow rates of temperature increase within containment as a result of environmental heat sources (due to the large volume of containment). Furthermore, the 24 hour Frequency is considered adequate in view of other indications available in the control room, including alarms, to alert the operator to an abnormal containment temperature condition.

REFERENCES

1. FSAR, Section 14.3.
2. 10 CFR 50.49.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.6 Containment Spray System and Containment Fan Cooler System

BASES

BACKGROUND

The Containment Spray System and Containment Fan Cooler System provide containment atmosphere cooling to limit post accident pressure and temperature in containment to less than the design values. Reduction of containment pressure and the iodine removal capability reduces the release of fission product radioactivity from containment to the environment, in the event of a Design Basis Accident (DBA), to within limits. The Containment Spray and Containment Fan Cooler systems are designed to meet the requirements of 10 CFR 50, Appendix A, GDC 38, "Containment Heat Removal," GDC 39, "Inspection of Containment Heat Removal Systems," GDC 40, "Testing of Containment Heat Removal Systems," GDC 41, "Containment Atmosphere Cleanup," GDC 42, "Inspection of Containment Atmosphere Cleanup Systems," and GDC 43, "Testing of Containment Atmosphere Cleanup Systems" (Ref. 1).

The Containment Spray System and Containment Fan Cooler System are Engineered Safety Feature (ESF) systems. They are designed to ensure that the heat removal capability required during the post accident period can be attained. The Containment Spray System and the Containment Fan Cooler System provide redundant methods to limit and maintain post accident conditions to less than the containment design values.

Containment Spray System

The Containment Spray System consists of two separate trains. Each train includes a containment spray pump, piping and valves and is independently capable of delivering one-half of the design flow needed to maintain the post-accident containment pressure below 47 psig. The spray water is injected into the containment through spray nozzles connected to four 360 degree ring headers located in the containment dome area. Each train supplies two of the four ring headers. Each train is powered from a separate safeguards power train. The refueling water storage tank (RWST) supplies borated water to the Containment Spray System during the injection phase of operation.

BASES

BACKGROUND

Containment Spray System (Continued)

After the Refueling Water Storage Tank has been exhausted, the containment recirculation pumps or the residual heat removal (RHR) pumps are used to supply the Containment Spray ring headers for the long-term containment cooling and iodine removal during the containment recirculation phase. In this configuration, the RHR heat exchangers provide the necessary cooling of the recirculated containment spray.

The Containment Spray System provides a spray of cold borated water mixed with sodium hydroxide (NaOH) from the spray additive tank into the upper regions of containment to reduce the containment pressure and temperature. Additionally, these systems reduce fission products from the containment atmosphere during a DBA. The RWST solution temperature is an important factor in determining the heat removal capability of the Containment Spray System during the injection phase. In the recirculation mode of operation, heat is removed from the containment sump or recirculation sump water by the residual heat removal heat exchangers. Both trains of the Containment Spray System are needed to provide adequate spray coverage to meet the system design requirements for containment heat removal assuming the Fan Cooler System is not available.

The Spray Additive System injects an NaOH solution into the spray. The resulting alkaline pH of the spray enhances the ability of the spray to scavenge fission products from the containment atmosphere. The NaOH added in the spray also ensures an alkaline pH for the solution recirculated in the containment sump. The alkaline pH of the containment sump water minimizes the evolution of iodine and minimizes the occurrence of chloride and caustic stress corrosion on mechanical systems and components exposed to the fluid.

The Containment Spray System is actuated either automatically by a containment High-High pressure signal or manually. An automatic actuation starts the two containment spray pumps, opens the containment spray pump discharge valves, and begins the injection phase. A manual actuation of the Containment Spray System requires the operator to actuate two separate push buttons on the main control board to begin the same sequence. The

BASES

BACKGROUND

Containment Spray System (Continued)

injection phase continues until the RWST water supply is exhausted. After the Refueling Water Storage Tank has been exhausted, the containment recirculation pumps or the residual heat removal (RHR) pumps may be used to supply the Containment Spray ring headers for the long-term containment cooling and iodine removal during the containment recirculation phase. In this configuration, the RHR heat exchangers provide the necessary cooling of the recirculated containment spray. The Containment Spray function in the recirculation mode may be used to maintain an equilibrium temperature between the containment atmosphere and the recirculated sump water. The Containment Spray function in the recirculation mode is controlled by the operator in accordance with the emergency operating procedures.

Containment Fan Cooler System

The Containment Fan Cooler System consists of five 20% capacity Fan Cooler Units (FCUs) located inside containment. These FCUs are used for both normal and post accident cooling of the containment atmosphere. Each FCU consists of a motor, fan, cooling coils, moisture separators, HEPA filters, carbon filters, dampers, duct distribution system, instrumentation and controls. Service water is supplied to the cooling coils to perform the heat removal function.

During normal plant operation, the moisture separators, HEPA filters and activated carbon filter assembly are isolated from the main air recirculation stream. In this configuration, service water is supplied to all five FCUs and two or more FCUs fans are typically operated to limit the ambient containment air temperature during normal unit operation to less than the limit specified in LCO 3.6.5, "Containment Air Temperature." This temperature limitation ensures that the containment temperature does not exceed the initial temperature conditions assumed for the DBAs.

In post accident operation following an actuation signal, the Containment Cooling System fans are designed to start automatically. Additionally, the actuation signal causes the air flow (air-steam mixture) in each FCU to be split into two parts

BASES

BACKGROUND

Containment Fan Cooler System (continued)

by a bypass flow control damper that fails to a pre-set position for accident operation. A minimum of 8000 cfm is directed through the FCU filtration section (moisture separators, HEPA filters, and carbon filter assembly) with the remainder of the air flow bypassing the filtration section. Both the filtered and unfiltered FCU flow passes through the cooling coils. The temperature of the service water is an important factor in the heat removal capability of the fan units. The accident analysis assumes 1400 gpm of service (cooling) water with a maximum river water inlet temperature of 95° F is supplied to each FCU.

Containment Cooling and Iodine Removal Function

The containment cooling and iodine removal function is provided by either of two systems:

a) the Containment Spray System consisting of two 50% capacity trains; and,

b) The Containment Fan Cooler System consisting of five 20% capacity Fan Cooler Units (FCUs).

Requirements for Containment Spray Trains may be designated by the number of the containment spray pump or the associated safeguards power train. Containment Spray Train 31 is associated with Safeguards Power Train 5A which is supported by DG 33. Containment Spray Train 32 is associated with Safeguards Power Train 6A which is supported by DG 32.

Requirements for the five fan cooler units are designated by grouping the 5 fan cooler units into three trains based on the safeguards power train needed to support Operability. This results in the following designations:

Fan Cooler Train 5A consists of FCU 31 and FCU 33;

Fan Cooler Train 2A/3A consists of FCU 32 and FCU 34; and

Fan Cooler Train 6A consists of FCU 35.

BASES

BACKGROUND

Containment Cooling and Iodine Removal Function (continued)

Design assumptions regarding containment air cooling and iodine removal are met by any of the following configurations:

a) Two containment spray trains; or,

b) Three fan cooler trains (i.e., five fan cooler units); or,

c) One containment spray train and any two fan cooler trains (i.e., at least three fan cooler units).

This last configuration, one containment spray train and two fan cooler trains, is the configuration available following the loss of any safeguards power train (e.g., diesel failure).

APPLICABLE SAFETY ANALYSES

The Containment Spray System and Containment Fan Cooler System limit the temperature and pressure that could be experienced following a DBA. The limiting DBAs considered are the loss of coolant accident (LOCA) and the steam line break (SLB). The LOCA and SLB are analyzed using computer codes designed to predict the resultant containment pressure and temperature transients. No DBAs are assumed to occur simultaneously or consecutively. The postulated DBAs are analyzed with regard to containment ESF systems, assuming the loss of one safeguards power train, which is the worst case single active failure and results in one train of Containment Spray and one train of Fan Coolers being rendered inoperable.

The analysis and evaluation show that under the worst case scenario, the highest peak containment pressure and temperature may result from either a LOCA or SLB, depending on the cycle specific analysis (Refs. 4 and 6). Both results meet the intent of the design basis. (See the Bases for LCO 3.6.4, "Containment Pressure," and LCO 3.6.5 for a detailed discussion.) The analyses and evaluations assume a unit specific power level of 102% and initial (pre-accident) containment conditions of 130°F

BASES

APPLICABLE SAFETY ANALYSES (continued)

and 2.5 psig and a service water inlet temperature of 95° F. The analyses also assume a response time delayed initiation to provide conservative peak calculated containment pressure and temperature responses.

For certain aspects of transient accident analyses, maximizing the calculated containment pressure is not conservative. In particular, the effectiveness of the Emergency Core Cooling System during the core reflood phase of a LOCA analysis increases with increasing containment backpressure. For these calculations, the containment backpressure is calculated in a manner designed to conservatively minimize, rather than maximize, the calculated transient containment pressures in accordance with 10 CFR 50, Appendix K (Ref. 2).

The modeled Containment Spray System actuation from the containment analysis is based on a response time associated with exceeding the containment High-High pressure setpoint to achieving full flow through the containment spray nozzles. The Containment Spray System total response time includes diesel generator (DG) startup (for loss of offsite power), loading of equipment, containment spray pump startup, and spray line filling.

Containment cooling train performance for post accident conditions is given in References 3, 4 and 6. The result of the analysis is that accident analysis assumptions regarding containment air cooling and iodine removal are met by any of the following configurations:

a) Two containment spray trains; or,

b) Three fan cooler trains (i.e., five fan cooler units); or,

c) One containment spray train and any two fan cooler trains (i.e., at least three fan cooler units).

BASES

APPLICABLE SAFETY ANALYSES (continued)

This last configuration, one containment spray train and two fan cooler trains, is the configuration available following the loss of any safeguards power train (e.g., diesel failure).

The modeled Containment Cooling System actuation from the containment analysis is based upon a response time associated with exceeding the containment High-High pressure setpoint to achieving full Containment Fan Cooler System air and safety grade cooling water flow. The Containment Cooling System total response time includes signal delay, DG startup (for loss of offsite power), and service water pump startup times (Ref.4).

The Containment Spray System and Containment Fan Cooler System satisfy Criterion 3 of 10 CFR 50.36.

LCO

Accident analysis assumptions regarding containment air cooling and iodine removal are met by any of the following configurations:

a) Two containment spray trains; or,

b) Three fan cooler trains (i.e., five fan cooler units); or,

c) One containment spray train and any two fan cooler trains (i.e., at least three fan cooler units).

This last configuration, one containment spray train and two fan cooler trains, is the configuration available following the loss of any safeguards power train (e.g., diesel failure).

Each Containment Spray System includes a spray pump, spray headers, nozzles, valves, piping, instruments, and controls to ensure an OPERABLE flow path capable of taking suction from the RWST upon an ESF actuation signal.

Each FCU consists of a motor, fan, cooling coils, moisture separators, HEPA filters, carbon filters, dampers, duct

BASES

LCO (continued)

distribution system, instrumentation and controls necessary to maintain an OPERABLE flow path for the containment atmosphere through both the filtration unit and cooling coils and an OPERABLE flow path for service water through the cooling coils.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment and an increase in containment pressure and temperature requiring the operation of the containment spray trains and containment cooling trains.

In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Thus, the Containment Spray System and Containment Fan Cooler System are not required to be OPERABLE in MODES 5 and 6.

ACTIONS

A.1

With one containment spray train inoperable, the inoperable containment spray train must be restored to OPERABLE status within 72 hours. In this Condition, the remaining OPERABLE spray and fan cooler trains are adequate to perform the iodine removal and containment cooling functions. The 72 hour Completion Time takes into account the redundant heat removal capability afforded by the Containment Spray System, reasonable time for repairs, and low probability of a DBA occurring during this period.

The 10 day portion of the Completion Time for Required Action A.1 is based upon engineering judgment. It takes into account the low probability of coincident entry into two Conditions in this Specification coupled with the low probability of an accident occurring during this time. Refer to Section 1.3, "Completion Times," for a more detailed discussion of the purpose of the "from discovery of failure to meet the LCO" portion of the Completion Time.

BASES

ACTIONS (continued)

B.1 and B.2

If the inoperable containment spray train cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 84 hours. The allowed Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems. The extended interval to reach MODE 5 allows additional time for attempting restoration of the containment spray train and is reasonable when considering the driving force for a release of radioactive material from the Reactor Coolant System is reduced in MODE 3.

C.1

With one of the required containment fan cooler trains inoperable, the inoperable required containment fan cooler train must be restored to OPERABLE status within 7 days. The components in this degraded condition provide iodine removal capabilities and are capable of providing at least 100% of the heat removal needs. The 7 day Completion Time was developed taking into account the redundant heat removal capabilities afforded by combinations of the Containment Spray System and Containment Fan Cooler System and the low probability of DBA occurring during this period.

The 10 day portion of the Completion Time for Required Action C.1 is based upon engineering judgment. It takes into account the low probability of coincident entry into two Conditions in this Specification coupled with the low probability of an accident occurring during this time. Refer to Section 1.3 for a more detailed discussion of the purpose of the "from discovery of failure to meet the LCO" portion of the Completion Time.

BASES

ACTIONS (continued)

D.1

With two required containment fan cooler trains inoperable, one of the required containment cooling trains must be restored to OPERABLE status within 72 hours. This allowable out of service time is acceptable because the minimum required containment cooling and iodine removal function is maintained even though this configuration is a substantial degradation from the design capability, and may be a loss of redundancy for this function.

E.1 and E.2

If the Required Action and associated Completion Time of Condition C or D of this LCO are not met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 84 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

F.1

With two containment spray trains or any combination of three or more containment spray and fan cooler trains inoperable, the unit could be in a condition outside the accident analysis. This Condition ensures that at least one containment spray train and one fan cooler train will be available during an accident. Entering this Condition represents a substantial degradation of the containment heat removal and iodine removal function. Therefore, LCO 3.0.3 must be entered immediately.

SURVEILLANCE REQUIREMENTS

SR 3.6.6.1

Verifying the correct alignment for manual, power operated, and automatic valves in the containment spray flow path provides

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.6.1 (continued)

assurance that the proper flow paths will exist for Containment Spray System operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these were verified to be in the correct position prior to locking, sealing, or securing. This SR does not require any testing or valve manipulation. Rather, it involves verification, through a system walkdown, that those valves outside containment and capable of potentially being mispositioned are in the correct position. Valves in containment with remote position indication may be checked using remote position indication.

SR 3.6.6.2

Operating each containment fan cooler unit for ≥ 15 minutes ensures that all fan cooler units are OPERABLE and that all associated controls are functioning properly. It also ensures that blockage, fan or motor failure, or excessive vibration can be detected for corrective action. The 92 day Frequency was developed considering fan coolers are operated during normal plant operation, the known reliability of the fan units and controls, the two train redundancy available, and the low probability of significant degradation of the containment fan cooler units occurring between surveillances. It has also been shown to be acceptable through operating experience.

SR 3.6.6.3

Verifying that the service water flow rate to each fan cooler unit is ≥ 1400 gpm provides assurance that the design flow rate assumed in the safety analyses will be achieved (Ref. 3). The 92 day Frequency was developed considering the known reliability of the Cooling Water System, the redundancy available, and the low probability of a significant degradation of flow occurring between surveillances.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.6.4

Verifying each containment spray pump's developed head at the flow test point is greater than or equal to the required developed head ensures that spray pump performance has not degraded during the cycle. Flow and differential pressure are normal tests of centrifugal pump performance required by Section XI of the ASME Code (Ref. 5). Since the containment spray pumps cannot be tested with flow through the spray headers, they are tested on recirculation flow. This test confirms one point on the pump design curve and is indicative of overall performance. Such inservice tests confirm component OPERABILITY, trend performance, and detect incipient failures by abnormal performance. The Frequency of the SR is in accordance with the Inservice Testing Program.

SR 3.6.6.5 and SR 3.6.6.6

These SRs require verification that each automatic containment spray valve actuates to its correct position and that each containment spray pump starts upon receipt of an actual or simulated actuation of a containment High-High pressure signal. This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The 24 month Frequency is based on the need to perform these Surveillances under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillances were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillances when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.6.6.7

This SR requires verification that each containment fan cooler unit starts and damper re-positions to the emergency mode upon receipt of an actual or simulated safety injection signal. The 24 month Frequency is based on engineering judgment and has been shown to be acceptable through operating experience. See

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.6.7 (continued)

SR 3.6.6.5 and SR 3.6.6.6, above, for further discussion of the basis for the 24 month Frequency.

SR 3.6.6.8

This SR verifies that the required Fan Cooler Unit testing is performed in accordance with Specification 5.5.10, Ventilation Filter Testing Program (VFTP). The VFTP includes testing the performance of the HEPA filter, charcoal adsorber efficiency, minimum flow rate, and the physical properties of the activated charcoal. Specific test Frequencies and additional information are discussed in detail in the VFTP.

SR 3.6.6.9

With the containment spray inlet valves closed and the spray header drained of any solution, low pressure air or smoke can be blown through test connections. This SR ensures that each spray nozzle is unobstructed and provides assurance that spray coverage of the containment during an accident is not degraded. Due to the passive design of the nozzle, a test at 10 year intervals is considered adequate to detect obstruction of the nozzles.

REFERENCES

1. 10 CFR 50, Appendix A.
2. 10 CFR 50, Appendix K.
3. FSAR, Sections 6.3 and 6.4.
4. FSAR, Section 14.3.
5. ASME, Boiler and Pressure Vessel Code, Section XI.
6. WCAP - 12269, Containment Margin Improvement Analysis for IP-3 Unit 3, Rev. 1.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.7 Spray Additive System

BASES

BACKGROUND

The Spray Additive System is a subsystem of the Containment Spray System that assists in reducing the iodine fission product inventory in the containment atmosphere resulting from a Design Basis Accident (DBA).

Radioiodine in its various forms is the fission product of primary concern in the evaluation of a DBA. It is absorbed by the spray from the containment atmosphere. To enhance the iodine absorption capacity of the spray, the spray solution is adjusted to an alkaline pH that promotes iodine hydrolysis, in which iodine is converted to nonvolatile forms. Because of its stability when exposed to radiation and elevated temperature, sodium hydroxide (NaOH) is the preferred spray additive. The NaOH added to the spray also ensures an alkaline pH of the solution recirculated from the containment sump. This pH band minimizes the evolution of iodine as well as the occurrence of chloride and caustic stress corrosion on mechanical systems and components.

The Spray Additive System consists of one spray additive tank that is shared by the two trains of containment spray. Each train provides a flow path from the spray tank to a containment spray pump and consists of an eductor for each containment spray pump, valves, instrumentation, and connecting piping. Each eductor draws the NaOH spray solution from the common tank using a portion of the borated water discharged by the containment spray pump as the motive flow. The eductor mixes the NaOH solution and the borated water and discharges the mixture into the spray pump suction line. The eductors are designed to ensure that the pH of the spray mixture is between 9.0 and 10.0.

The Containment Spray System actuation signal opens the valves from the spray additive tank to the spray pump suctions after a 2 minute delay. The 35% to 38% NaOH solution is drawn into the spray pump suctions. The spray additive tank capacity provides for the addition of NaOH solution to all of the water sprayed from the RWST into containment via the Containment Spray System.

BASES

BACKGROUND (Continued)

The percent solution and volume of solution sprayed into containment ensures a long term equilibrium containment sump pH of approximately 9.0. This ensures the continued iodine retention effectiveness of the sump water during the recirculation phase of spray operation and also minimizes the occurrence of chloride induced stress corrosion cracking of the stainless steel recirculation piping.

APPLICABLE SAFETY ANALYSES

The Spray Additive System, in conjunction with the Fan Cooler System, is essential to the removal of airborne iodine within containment following a DBA.

Following the assumed release of radioactive materials into containment, the containment is assumed to leak at its design value volume following the accident. The analysis assumes that 100% of containment is covered by the spray (Ref. 1).

The DBA response time assumed for the Spray Additive System is the same as for the Containment Spray System (plus a 2 minute delay) and is discussed in the Bases for LCO 3.6.6, "Containment Spray and Fan Cooler System."

The DBA analyses assume that one train of the Containment Spray System is inoperable and that the spray additive is added to the remaining Containment Spray System flow path.

The Spray Additive System satisfies Criterion 3 of 10 CFR 50.36.

LCO

The Spray Additive System reduces the release of radioactive material to the environment in the event of a DBA. To be considered OPERABLE, the volume and concentration of the spray additive solution must be sufficient to provide NaOH injection into the spray flow until the Containment Spray System suction path is switched from the RWST to the recirculation sump or

BASES

LCO (continued)

containment sump, and to raise the average spray solution pH to a level conducive to iodine removal, namely, to between 7.9 and 10.0. This pH range maximizes the effectiveness of the iodine removal mechanism without introducing conditions that may induce caustic stress corrosion cracking of mechanical system components. In addition, it is essential that valves in the Spray Additive System flow paths are properly positioned and that automatic valves are capable of activating to their correct positions.

APPLICABILITY

In MODES 1, 2, 3, and 4, a DBA could cause a release of radioactive material to containment requiring the operation of the Spray Additive System. The Spray Additive System assists in reducing the iodine fission product inventory prior to release to the environment.

In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Thus, the Spray Additive System is not required to be OPERABLE in MODE 5 or 6.

ACTIONS

A.1

If the Spray Additive System is inoperable, it must be restored to OPERABLE within 72 hours. The pH adjustment of the Containment Spray System flow for corrosion protection and iodine removal enhancement is reduced in this condition. The Containment Spray System and Containment Fan Cooler System are available and would remove iodine from the containment atmosphere in the event of a DBA. The 72 hour Completion Time takes into account the redundant flow path capabilities and the low probability of the worst case DBA occurring during this period.

BASES

ACTIONS (continued)

B.1 and B.2

If the Spray Additive System cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 84 hours. The allowed Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems. The extended interval to reach MODE 5 allows 48 hours for restoration of the Spray Additive System in MODE 3 and 36 hours to reach MODE 5. This is reasonable when considering the reduced pressure and temperature conditions in MODE 3 for the release of radioactive material from the Reactor Coolant System.

SURVEILLANCE REQUIREMENTS

SR 3.6.7.1

Verifying the correct alignment of Spray Additive System manual, power operated, and automatic valves in the spray additive flow path provides assurance that the system is able to provide additive to the Containment Spray System in the event of a DBA. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these valves were verified to be in the correct position prior to locking, sealing, or securing. This SR does not require any testing or valve manipulation. Rather, it involves verification, through a system walkdown, that those valves outside containment and capable of potentially being mispositioned are in the correct position.

SR 3.6.7.2

To provide effective iodine removal, the containment spray must be an alkaline solution. Since the RWST contents are normally acidic, the volume of the spray additive tank must provide a sufficient volume of spray additive to adjust pH for all water

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.7.2 (continued)

injected. This SR is performed to verify the availability of sufficient NaOH solution in the Spray Additive System. The 184 day Frequency was developed based on the low probability of an undetected change in tank volume occurring during the SR interval (the tank is isolated during normal unit operations). Tank level is also indicated and alarmed in the control room, so that there is high confidence that a substantial change in level would be detected.

SR 3.6.7.3

This SR provides verification of the NaOH concentration in the spray additive tank and is sufficient to ensure that the spray solution being injected into containment is at the correct pH level. The 184 day Frequency is sufficient to ensure that the concentration level of NaOH in the spray additive tank remains within the established limits. This is based on the low likelihood of an uncontrolled change in concentration (the tank is normally isolated) and the probability that any substantial variance in tank volume will be detected.

SR 3.6.7.4

This SR provides verification that each automatic valve in the Spray Additive System flow path actuates to its correct position. This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.7.5

To ensure that the correct pH level is established in the borated water solution provided by the Containment Spray System, flow in the Spray Additive System is verified once every 5 years. This SR provides assurance that NaOH will be introduced into the flow path upon Containment Spray System initiation. This test is satisfied by the Inservice Test Program verification of the spray additive tank check valve. Water may be used in lieu of NaOH for the performance of this SR which is not intended to require transfer of NaOH. Due to the passive nature of the spray additive flow controls, the 5 year Frequency is sufficient to identify component degradation that may affect flow.

REFERENCES

1. FSAR, Chapters 6 and 14.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.8 Hydrogen Recombiners

BASES

BACKGROUND

The function of the hydrogen recombiners is to eliminate the potential breach of containment due to a hydrogen oxygen reaction.

Per 10 CFR 50.44, "Standards for Combustible Gas Control Systems in Light-Water-Cooled Reactors" (Ref. 1), and GDC 41, "Containment Atmosphere Cleanup" (Ref. 2), hydrogen recombiners are required to reduce the hydrogen concentration in the containment following a loss of coolant accident (LOCA) or steam line break (SLB). The recombiners accomplish this by recombining hydrogen and oxygen to form water vapor. The vapor remains in containment, thus eliminating any discharge to the environment. The hydrogen recombiners are manually initiated since flammable limits would not be reached until several days after a Design Basis Accident (DBA).

Two 100% capacity independent hydrogen recombiner systems are provided. Each consists of controls located in the control room, a power supply and a recombiner. Recombination is accomplished by heating a hydrogen air mixture above 1150°F. A single recombiner is capable of maintaining the hydrogen concentration in containment below the 4.1 volume percent (v/o) flammability limit. Two recombiners are provided to meet the requirement for redundancy and independence. Each recombiner is powered from a separate Engineered Safety Features bus, and is provided with a separate power panel and control panel.

APPLICABLE SAFETY ANALYSES

The hydrogen recombiners provide for the capability of controlling the bulk hydrogen concentration in containment to less than the lower flammable concentration of 4.1 v/o following a DBA. This control would prevent a containment wide hydrogen burn, thus ensuring the pressure and temperature assumed in the analyses are not exceeded. The limiting DBA relative to

BASES

APPLICABLE SAFETY ANALYSES (continued)

hydrogen generation is a LOCA. Hydrogen may accumulate in containment following a LOCA as a result of:

a. A metal steam reaction between the zirconium fuel rod cladding and the reactor coolant;

b. Radiolytic decomposition of water in the Reactor Coolant System (RCS) and the containment sump;

c. Hydrogen in the RCS at the time of the LOCA (i.e., hydrogen dissolved in the reactor coolant and hydrogen gas in the pressurizer vapor space); or

d. Corrosion of metals exposed to containment spray and Emergency Core Cooling System solutions.

To evaluate the potential for hydrogen accumulation in containment following a LOCA, the hydrogen generation as a function of time following the initiation of the accident is calculated. Conservative assumptions recommended by Reference 3 are used to maximize the amount of hydrogen calculated.

Based on the conservative assumptions used to calculate the hydrogen concentration versus time after a LOCA, the hydrogen concentration in the primary containment would reach 2.0 v/o about 5 days after the LOCA and 3.0 v/o about 10 days later if no recombiner was functioning (Ref. 3). Initiating the hydrogen recombiners when the primary containment hydrogen concentration reaches 3.0 v/o will maintain the hydrogen concentration in the primary containment below flammability limits.

The hydrogen recombiners are designed such that, with the conservatively calculated hydrogen generation rates discussed above, a single recombiner is capable of limiting the peak hydrogen concentration in containment to less than 4.0 v/o (Ref. 3).

The hydrogen recombiners satisfy Criterion 3 of 10 CFR 50.36.

BASES

LCO

Two hydrogen recombiners must be OPERABLE. This ensures operation of at least one hydrogen recombiner in the event of a worst case single active failure.

Operation with at least one hydrogen recombiner ensures that the post LOCA hydrogen concentration can be prevented from exceeding the flammability limit.

APPLICABILITY

In MODES 1 and 2, two hydrogen recombiners are required to control the hydrogen concentration within containment below its flammability limit of 4.1 v/o following a LOCA, assuming a worst case single failure.

In MODES 3 and 4, both the hydrogen production rate and the total hydrogen produced after a LOCA would be less than that calculated for the DBA LOCA. Also, because of the limited time in these MODES, the probability of an accident requiring the hydrogen recombiners is low. Therefore, the hydrogen recombiners are not required in MODE 3 or 4.

In MODES 5 and 6, the probability and consequences of a LOCA are low, due to the pressure and temperature limitations in these MODES. Therefore, hydrogen recombiners are not required in these MODES.

ACTIONS

A.1

With one containment hydrogen recombiner inoperable, the inoperable recombiner must be restored to OPERABLE status within 30 days. In this condition, the remaining OPERABLE hydrogen recombiner is adequate to perform the hydrogen control function. However, the overall reliability is reduced because a single failure in the OPERABLE recombiner could result in reduced hydrogen control capability. The 30 day Completion Time is based on the availability of the other hydrogen recombiner, the small probability of a LOCA or SLB occurring (that would generate an amount of hydrogen that exceeds the flammability limit), and the amount of time available after a LOCA or SLB (should one occur)

BASES

ACTIONS

A.1 (continued)

for operator action to prevent hydrogen accumulation from exceeding the flammability limit.

Required Action A.1 has been modified by a Note that states the provisions of LCO 3.0.4 are not applicable. As a result, a MODE change is allowed when one recombiner is inoperable. This allowance is based on the availability of the other hydrogen recombiner, the small probability of a LOCA or SLB occurring (that would generate an amount of hydrogen that exceeds the flammability limit), and the amount of time available after a LOCA or SLB (should one occur) for operator action to prevent hydrogen accumulation from exceeding the flammability limit.

B.1

If the inoperable hydrogen recombiner cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours. The Completion Time of 6 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.8.1

Performance of a system functional test for each hydrogen recombiner ensures the recombiners are operational and can attain and sustain the temperature necessary for hydrogen recombination. In particular, this SR verifies that the minimum heater sheath temperature increases to ≥ 700°F in ≤ 90 minutes. After reaching 700°F, the power is increased to maximum power for approximately 2 minutes and power is verified to be ≥ 60 kW.

Operating experience has shown that these components usually pass the Surveillance when performed at the 6 month Frequency.

SURVEILLANCE REQUIREMENTS

SR 3.6.8.1 (continued)

Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.6.8.2

This SR ensures there are no physical problems that could affect recombiner operation. Since the recombiners are mechanically passive, they are not subject to mechanical failure. The only credible failure involves loss of power, blockage of the internal flow, missile impact, etc.

A visual inspection is sufficient to determine abnormal conditions (e.g., loose wiring or structural connections, deposits of foreign materials, etc.) that could cause such failures. The 24 month Frequency for this SR was developed considering the incidence of hydrogen recombiners failing the SR in the past is low.

SR 3.6.8.3

This SR requires performance of a resistance to ground test for each heater phase to ensure that there are no detectable grounds in any heater phase. This is accomplished by verifying that the resistance to ground for any heater phase is ≥ 10,000 ohms.

The 24 month Frequency for this Surveillance was developed considering the incidence of hydrogen recombiners failing the SR in the past is low.

REFERENCES

1. 10 CFR 50.44.
2. 10 CFR 50, Appendix A.
3. FSAR Section 6.8.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.9 Isolation Valve Seal Water (IVSW) System

BASES

BACKGROUND

The Isolation Valve Seal Water (IVSW) System improves the effectiveness of certain containment isolation valves (CIVs) by providing a water seal to valve leakage paths. This is accomplished by injecting water between the seats and stem packing of globe and double-disk type isolation valves and into the piping between other closed containment isolation valves. IVSW sealing water is maintained in a seal water supply tank filled with water and pressurized with nitrogen. The IVSW System is actuated in conjunction with automatic initiation of containment isolation and is applied to CIVs in lines connected to the Reactor Coolant System or exposed to the containment atmosphere during an accident. The seal water is injected at a pressure of at least 47 psig which is > 1.1 times the calculated peak containment pressure (P_a). For those valves sealed by IVSW, the possibility of leakage from the Containment or Reactor Coolant System to the atmosphere outside containment is eliminated because leakage will be from the IVSW system into the Containment.

The containment is designed with an allowable leakage rate not to exceed 0.1% of the containment air weight per day. The maximum allowable leakage rate is used to evaluate offsite doses resulting from a DBA. Confirmation that the leakage rate is within limit is demonstrated by the performance of a Type A leakage rate test in accordance with the Containment Leakage Rate Testing Program as required by LCO 3.6.1, "Containment." During the performance of the Type A test, no credit is taken for the IVSW System in meeting the containment leakage rate criteria. As such, in the event of a DBA without an OPERABLE IVSW System, both the whole body and thyroid offsite doses would be within the guidelines specified in 10 CFR Part 100.

Although IVSW is not needed to maintain plant releases such that the whole body and thyroid offsite doses would be within the guidelines specified in 10 CFR Part 100 based on Type A leakage testing, Indian Point 3 elected to consider IVSW as a seal system

BASES

BACKGROUND (continued)

as described in 10 CFR 50, Appendix J, (Ref. 3). This election allows leakage through CIVs sealed by IVSW to be excluded when calculating Type B and C testing results. Therefore, operation of IVSW is an implicit assumption in the calculation of post accident offsite radiation doses.

To satisfy the requirements of 10 CFR 50, Appendix J, for excluding leakage from CIVs sealed by IVSW from Type B and C limits, Technical Specifications must ensure the IVSW sealing function (i.e., both sealing water supply and nitrogen gas supply) is maintained at a pressure of 1.10 P_a for at least 30 days.

Sealing water design capacity is sufficient to maintain a source of seal water at the required pressure for a minimum of 24 hours without operator intervention assuming worst case leakage and the single failure of a CIV sealed by IVSW. The requirements for a 24 hour supply of seal water under worst case conditions is satisfied by maintaining a minimum of 144 gallons in the 176 gallon capacity seal water tank.

Nitrogen gas for IVSW seal water pressurization is satisfied by having three compressed nitrogen bottles in the IVSW supply bank aligned to the IVSW supply tank.

To satisfy the requirement of 10 CFR 50, Appendix J, (Ref. 3) for maintaining the IVSW sealing function for at least 30 days, manual operator action may be required to replenish the IVSW seal water supply and/or compressed gas supply. Two sources of makeup water and two alternate sources of compressed gas with sufficient capacity to maintain the IVSW sealing function for 30 days are available. The two sources of makeup water are the primary water storage tank and the city water system. The two alternate sources of compressed gas are the normally isolated nitrogen gas bottles in the nitrogen supply bank and the ability to refill the IVSW nitrogen supply bottles from the plant Nitrogen System. Manual operations required to supply makeup water and gas to the IVSW system are performed in an area that is accessible during an accident.

BASES

BACKGROUND (continued)

The IVSW tank is instrumented to provide local indication of pressure and water level. Low water level, low pressure and high pressure in the IVSW supply tank are alarmed.

The IVSW System distribution piping consists of five headers. Three of the five IVSW headers are pressurized by opening either of a pair of normally closed air operated header injection valves. These valves open automatically on a containment Phase "A" isolation signal to admit seal water to the associated CIVs. One of the five IVSW headers is pressurized by opening either of a pair of normally closed, air-motor operated, header injection valves. These valves open automatically on a containment Phase "A" isolation signal to admit seal water to the associated CIVs. One IVSW header is used to supply seal water to CIVs on process lines that are not automatically closed on a containment Phase "A" isolation signal. This header is normally pressurized by the IVSW System with a normally closed manual or air-motor operated isolation valve for each pair of CIVs served by this IVSW header.

Redundant automatic header injection valves in parallel ensures the IVSW header is pressurized if there is a failure of one injection valve. Each of the two automatic header injection valves in each pair are actuated from separate and independent signals.

A related system, the Isolation Valve Seal Gas System, is not credited as a seal system as described in 10 CFR 50, Appendix J, and is not addressed by this Technical Specification. This system uses the nitrogen bank used to supply the IVSW System to supply high pressure nitrogen that may be used to seal lines subjected to pressure in excess of the 150 psig IVSW design pressure due to operation of the recirculation pumps. This system is manually initiated during the post accident recovery phase and is not part of the IVSW System.

BASES

APPLICABLE SAFETY ANALYSES

The IVSW System LCO was derived from the requirement related to the control of leakage from the containment during major accidents. This LCO is intended to ensure the actual containment leakage rate is maintained within the maximum value assumed in the safety analyses. As part of the containment boundary, containment isolation valves function to support the leak tightness of the containment. The IVSW System assures the effectiveness of certain containment isolation valves by providing a water seal pressurized to ≥ 1.1 times the maximum peak containment accident pressure at the valves and thereby reducing containment leakage. As such, the IVSW System is considered a seal system as described in 10 CFR 50, Appendix J. Therefore, the safety analyses of any event requiring isolation of containment is applicable to this LCO.

The DBA that results in a release of radioactive material within containment is a loss of coolant accident (LOCA)(Ref. 2). The DBAs assume that, within 60 seconds after the accident, isolation of the containment is complete and leakage terminated except for the design leakage rate, L_a. The containment isolation total response time of 60 seconds includes signal delay, diesel generator startup (for loss of offsite power) and containment isolation valve stroke time. The IVSW System actuates on a containment isolation signal and functions within 60 seconds to help reduce containment leakage within the allowable design leakage rate value, L_a.

The Isolation Valve Seal Water System satisfies Criterion 3 of 10 CFR 50.36.

LCO

OPERABILITY of the IVSW System is based on the system's capability to supply seal water to selective containment isolation valves within the time assumed in the applicable safety analyses and to ensure pressure is maintained for at least 30 days. This requires the IVSW tank be maintained with an adequate volume of water, an air or nitrogen overpressure sufficient to provide the motive force to move the water to the applicable

BASES

LCO (continued)

penetration, piping to provide an OPERABLE flow path and two air operated header injection valves on each automatically actuated branch header.

APPLICABILITY

The IVSW System is required to be OPERABLE in MODES 1, 2, 3, and 4 because a DBA could cause a release of radioactive material to containment. In MODES 5 and 6, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, the IVSW System is not required to be OPERABLE in MODE 5 or 6.

ACTIONS

A.1

With one IVSW System header inoperable, a portion of the CIVs serviced by IVSW may not receive seal water at the required pressure and volume for effective sealing. However, the CIVs are OPERABLE and will still close, the affected CIVs provide adequate isolation to meet containment isolation requirements without IVSW during the most recent Type A test, and the number of CIVs affected by the failure of one IVSW header is small compared to the total number of CIVs. Therefore, the 7 days is allowed to restore the IVSW System header to OPERABLE status.

With one IVSW automatic actuation valve inoperable, the IVSW function is still available because the redundant automatic actuation valve is OPERABLE. Therefore, the 7 days is allowed to restore the IVSW automatic actuation valve to OPERABLE status.

B.1

With the IVSW system inoperable for reasons other than Condition A, the effectiveness of CIVs sealed by IVSW may be compromised. This Condition may result from failure to meet any of the surveillance requirements needed to verify Operability of IVSW or the inoperability of multiple IVSW headers or automatic actuation

BASES

ACTIONS

B.1 (continued)

devices. However, the CIVs are OPERABLE and will still close and the affected CIVs provide adequate isolation to meet containment isolation requirements without IVSW during the most recent Type A test. Additionally, except in the unusual case where inoperability is the result of failure to meet SR 3.6.9.5, the affected CIVs have demonstrated the ability to satisfy IVSW leakage requirements using IVSW seal water in lieu of meeting Type C testing requirements. Therefore, the 24 hours is allowed to restore the IVSW System to OPERABLE status.

C.1 and C.2

If the Required Actions and associated Completion Times are not met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems

SURVEILLANCE REQUIREMENTS

SR 3.6.9.1

This SR verifies the IVSW tank has the necessary pressure to provide motive force to the seal water. A 47 psig pressure is sufficient to ensure the containment penetration flowpaths that are sealed by the IVSW System are maintained at a pressure equal to or greater than 1.1 times the calculated peak containment internal pressure (Pa) related to the design bases accident. Verification of the IVSW tank pressure on a Frequency of once per 24 hours is acceptable because operating experience has shown this Frequency to be appropriate for early detection and correction of off normal trends.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.9.2

This SR ensures the capability of the IVSW nitrogen source to pressurize the IVSW system as needed to support IVSW operation for a minimum of 30 days. Verification of the IVSW tank pressure on a Frequency of once per 24 hours is acceptable because operating experience has shown this Frequency to be appropriate for early detection and correction of off normal trends.

SR 3.6.9.3

This SR verifies the IVSW tank has an initial volume of water necessary to provide seal water to the containment isolation valves served by the IVSW System for a period of at least 24 hours assuming the failure of one CIV and the maximum allowed leakage past other CIVs served by IVSW. Verification of IVSW tank level on a Frequency of once per 24 hours is acceptable since tank level is monitored by installed instrumentation and will alarm in the Primary Auxilliary Building prior to level decreasing to 80 gallons.

SR 3.6.9.4

This SR verifies the stroke time of each automatic IVSW header injection solenoid valve is within limits. The frequency is specified by the Inservice Testing Program, and previous operating experience has shown that these valves usually pass the required test when performed.

SR 3.6.9.5

This SR ensures that automatic header injection valves actuate to the correct position on a simulated or actual signal. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at the 24 month Frequency.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.9.6

Integrity of the IVSW seal boundary is important in providing assurance that the design leakage value required for the system to perform its sealing function is not exceeded. This testing is performed in accordance with the requirements, Frequency and acceptance criteria established in Specification 5.5.15, Containment Leakage Rate Testing Program. This program was established to implement the leakage rate testing of the containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B, as modified by IP3 specific approved exemptions. This program conforms to guidelines contained in Regulatory Guide 1.163, "Performance-Based Containment Leak Test Program, dated September 1995."

REFERENCES

1. FSAR, Section 6.
2. FSAR, Chapter 14.
3. 10 CFR 50, Appendix J.

B 3.7 PLANT SYSTEMS

B 3.7.1 Main Steam Safety Valves (MSSVs)

BASES

BACKGROUND

The primary purpose of the MSSVs is to provide overpressure protection for the secondary system. The MSSVs also provide protection against overpressurizing the reactor coolant pressure boundary (RCPB) by providing a heat sink for the removal of energy from the Reactor Coolant System (RCS) if the preferred heat sink, provided by the Condenser and Circulating Water System, is not available.

Five MSSVs are located on each main steam header, outside containment, upstream of the main steam isolation valves and non-return valves, as described in the FSAR, Section 10.2 (Ref. 1). The five code safety valves per steam generator consist of four 6 inch by 10 inch and one 6 inch by 8 in. These valves are set to open at 1065, 1080, 1095, 1110 and 1120 psig, respectively. The steam generator safety valve capacity is rated to remove the maximum calculated steam flow (normally 105% of the maximum guaranteed steam flow) from the steam generators without exceeding 110% of the steam system design pressure, (Ref. 2). The MSSV design includes staggered setpoints, according to Table 3.7.1-2 in the accompanying LCO, so that only the needed valves will actuate. Staggered setpoints reduce the potential for valve chattering that is due to steam pressure insufficient to fully open all valves following a turbine or reactor trip.

APPLICABLE SAFETY ANALYSES

The design basis for the MSSVs comes from Reference 2 and its purpose is to limit the secondary system pressure to ≤ 110% of design pressure when passing 100% of design steam flow. This design basis is sufficient to cope with any anticipated operational occurrence (AOO) or accident considered in the Design Basis Accident (DBA) and transient analysis.

The events that challenge the relieving capacity of the MSSVs, and thus RCS pressure, are those characterized as decreased heat

BASES

APPLICABLE SAFETY ANALYSES (continued)

removal events, which are presented in the FSAR, Section 14 (Ref. 3). Of these, the full power loss of external electrical load without steam dump is the limiting AOO.

The transient response for loss of external electrical load without a direct reactor trip presents no hazard to the integrity of the RCS or the Main Steam System. If a minimum reactivity feedback is assumed, the reactor is tripped on high pressurizer pressure. In this case, the pressurizer safety valves open, and RCS pressure remains below 110% of the design value. The MSSVs also open to limit the secondary steam pressure.

If maximum reactivity feedback is assumed, the reactor is tripped on overtemperature ΔT. The departure from nucleate boiling ratio increases throughout the transient, and never drops below its initial value. Pressurizer relief valves and MSSVs are activated and prevent overpressurization in the primary and secondary systems.

The MSSVs satisfy Criterion 3 of 10 CFR 50.36.

LCO

The accident analysis requires five MSSVs per steam generator to provide overpressure protection for design basis transients occurring at 102% RTP. An MSSV will be considered inoperable if it fails to open on demand. The LCO requires that five MSSVs be OPERABLE in compliance with Reference 2. This is because operation with less than the full number of MSSVs requires limitations on allowable THERMAL POWER (to meet ASME Code requirements). These limitations are according to Table 3.7.1-1 in the accompanying LCO, and Required Action A.1.

The OPERABILITY of the MSSVs is defined as the ability to open within the setpoint tolerances, relieve steam generator overpressure, and reseat when pressure has been reduced. The OPERABILITY of the MSSVs is determined by periodic surveillance testing in accordance with the Inservice Testing Program.

BASES

LCO (continued)

The lift settings, according to Table 3.7.1-2 in the accompanying LCO, correspond to ambient conditions of the valve at nominal operating temperature and pressure.

This LCO provides assurance that the MSSVs will perform their designed safety functions to mitigate the consequences of accidents that could result in a challenge to the RCPB.

APPLICABILITY

In MODE 1 above 23% RTP, the number of MSSVs per steam generator required to be OPERABLE must be according to Table 3.7.1-1 in the accompanying LCO. Below 23% RTP in MODES 1, 2, and 3, only two MSSVs per steam generator are required to be OPERABLE.

In MODES 4 and 5, there are no credible transients requiring the MSSVs. The steam generators are not normally used for heat removal in MODES 5 and 6, and thus cannot be overpressurized; there is no requirement for the MSSVs to be OPERABLE in these MODES.

ACTIONS

The ACTIONS table is modified by a Note indicating that separate Condition entry is allowed for each MSSV.

A.1

With one or more MSSVs inoperable, reduce neutron flux trip setpoint so that the available MSSV relieving capacity address the issues raised in Nuclear Safety Advisory Letter (NSAL) 94-001, Operation at Reduced Power Levels with Inoperable Main Steam Safety Valves (Ref. 6).

Operation with less than all five MSSVs OPERABLE for each steam generator is permissible, if THERMAL POWER is proportionally limited to the relief capacity of the remaining MSSVs. This is accomplished by reducing the neutron flux trip setpoint and reducing THERMAL POWER so that the energy transfer to the most

BASES

ACTIONS

A.1 (continued)

limiting steam generator is not greater than the available relief capacity in that steam generator.

Startup and power operation with up to three of the five MSSVs associated with each steam generator inoperable is permissible if the maximum allowed power level is below the heat removing capability of the operable MSSVs. Therefore, startup and power operation with inoperable main steam line safety valves is allowable if the neutron flux trip setpoints are restricted within the limits specified in Table 3.7.1-1. This ensures that reactor power level is limited so that the heat input from the primary side will not exceed the heat removing capability of the OPERABLE MSSVs of the most limiting steam generator. The reduction in reactor power level is achieved by reducing the power range neutron flux high setpoint. The reactor trip setpoint reductions are derived on the following basis:

$$Hi\phi = (100 / Q)\ [(ws h_{fg} N) / K]$$

Where:

$Hi\phi$ = Safety Analysis high neutron flux setpoint (% RTP);

Q = Nominal NSSS power rating of the plant (including reactor coolant pump heat) in Mwt (i.e.,3037 Mwt);

K = Conversion factor, 947.82 (Btu/sec)/Mwt;

ws = Minimum total steam flow rate capability of the operable MSSVs on any one steam generator at the highest MSSV opening pressure, including tolerance and accumulation, as appropriate, in lb/sec. (ws = 150 + 228.61 * (4 - V) lb/sec, where V = Number of inoperable safety valves in the steam line of the most limiting steam generator).

BASES

ACTIONS A.1 (continued)

h_{fg} = Heat of vaporization for steam at the highest MSSV opening pressure including tolerance and accumulation, as appropriate, Btu/lbm (i.e.,608.5 Btu/lbm).

N = Number of loops in plant (i.e., 4).

B.1 and B.2

If the MSSVs cannot be restored to OPERABLE status within the associated Completion Time, or if one or more steam generators have less than two MSSVs OPERABLE, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.1.1

This SR verifies the OPERABILITY of the MSSVs by the verification of each MSSV lift setpoint in accordance with the Inservice Testing Program. The ASME Code, Section XI (Ref. 4), requires that safety and relief valve tests be performed in accordance with ANSI/ASME OM-1-1987 (Ref. 5). According to Reference 5, the following tests are required:

a. Visual examination;

b. Seat tightness determination;

c. Setpoint pressure determination (lift setting); and

d. Compliance with owner's seat tightness criteria.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.1.1 (continued)

The ANSI/ASME Standard requires that all valves be tested every 5 years, and a minimum of 20% of the valves be tested every 24 months. The ASME Code specifies the activities and frequencies necessary to satisfy the requirements. Table 3.7.1-2 allows a ± 3% setpoint tolerance for OPERABILITY; however, the valves are reset to ± 1% during the Surveillance to allow for drift.

This SR is modified by a Note that allows entry into and operation in MODE 3 prior to performing the SR. The MSSVs may be either bench tested or tested in situ at hot conditions using an assist device to simulate lift pressure. If the MSSVs are not tested at hot conditions, the lift setting pressure shall be corrected to ambient conditions of the valve at operating temperature and pressure.

REFERENCES

1. FSAR, Section 10.2.
2. ASME, Boiler and Pressure Vessel Code, Section III, 1971 Edition.
3. FSAR, Section 14.
4. ASME, Boiler and Pressure Vessel Code, Section XI.
5. ANSI/ASME OM-1-1987.
6. Nuclear Safety Advisory Letter (NSAL) 94-001, Operation at Reduced Power Levels with Inoperable Main Steam Safety Valves

B 3.7 PLANT SYSTEMS

B 3.7.2 Main Steam Isolation Valves (MSIVs) and Main Steam Check Valves (MSCVs)

BASES

BACKGROUND

The Main Steam System conducts steam from each of the four steam generators within the containment building to the turbine stop and control valves. The four steam lines are interconnected near the turbine. Each steam line is equipped with an isolation valve identified as the Main Steam Isolation Valve (MSIV) and a non-return valve identified as the Main Steam Check Valve (MSCV).

The MSIVs isolate steam flow from the secondary side of the steam generators following a high energy line break (HELB). MSIV closure terminates flow from the unaffected (intact) steam generators.

The MSIVs are swing disc type check valves that are aligned to prevent flow out of the steam generator. During normal operation, the free swinging discs in the MSIVs are held out of the main steam flow path by an air piston and the MSIVs close to prevent the release of steam from the SG when air is removed from the piston. The isolation valves are designed to and required to close in less than five seconds. The MSIV operators are supplied by instrument air and each MSIV is equipped with an air receiver to prevent spurious MSIV closure due to pressure transients in the instrument air system.

Each MSIV is equipped with a bypass valve used to warm up the steam line during unit startup which equalizes pressure across the valve allowing it to be opened. The bypass valves are manually operated and are closed during normal plant operation.

An MSIV closure signal is generated by the following signals:

High steam flow in any two out of the four steam lines coincident with low steam line pressure; or,

High steam flow in any two out of the four steam lines coincident with low Tavg; or,

BASES

BACKGROUND (continued)

Two sets of the two-of-three high-high containment pressure signals; or,

Manual actuation using a separate switch in the control room for each MSIV.

Note that a turbine trip is initiated whenever an MSIV is not fully open.

The MSCVs are swing disc type check valves that are aligned to prevent reverse flow of steam into an SG if an individual SG pressure falls below steamline pressure.

One MSIV and one MSCV are located in each main steam line outside but close to containment. The MSIVs are downstream from the main steam safety valves (MSSVs) and auxiliary feedwater (AFW) pump turbine steam supply to prevent MSSV and AFW isolation from the steam generators by MSIV closure. Closing the MSIVs isolates each steam generator from the others, and isolates the turbine, Steam Bypass System (High Pressure Steam Dump), and other auxiliary steam supplies from the steam generators.

A description of the MSIVs and MSCVs is found in the FSAR, Section 10.2 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The design basis of the MSIVs is established by the containment analysis for the large steam line break (SLB) inside containment (Ref. 2) and the accident analysis of the SLB events presented in the FSAR, Sections 6.2 and 14.2 (References 2 and 3, respectively). The combination of MSIVs and MSCVs precludes the blowdown of more than one steam generator, assuming a single active component failure (e.g., the failure of one MSIV to close on demand). For a break upstream of an MSIV, either the MSIVs in the other three steam lines or the MSCV in the steam line with the faulted SG must close to prevent the blowdown of

BASES

APPLICABLE SAFETY ANALYSES (continued)

more than one SG. For a break downstream of an MSIV, the MSCVs are not required to function.

The limiting case for the containment analysis is the SLB inside containment, without a loss of offsite power and failure to close of the MSCV on the affected steam generator or the failure to close of the MSIV associated with any other SG. With either of these failures, only one SG blows down.

The limiting SLBs occur at low power or hot shutdown because the magnitude and duration of the RCS cooldown will be greater if the SLB is initiated from these conditions. This occurs because, at low power conditions, there is less stored energy in the fuel and the initial steam generator water inventory is greatest at no load. Additionally, the magnitude and duration of the RCS cooldown will be greater if RCPs continue to operate during the SLB. Therefore, an SLB without loss of offsite power is more limiting.

If it is assumed that the most reactive rod cluster control assembly is stuck in the fully withdrawn position, there is an increased possibility that the core will become critical and return to power. In the most limiting condition, the core is ultimately shut down by the boric acid injection delivered by the Emergency Core Cooling System.

The accident analysis compares several different SLB events against different acceptance criteria. The large SLB outside containment upstream of the MSIV is limiting for offsite dose, although a break in this short section of main steam header has a very low probability. The large SLB inside containment at hot zero power with offsite power available is the limiting case for a post trip return to power. The analysis includes scenarios with offsite power available, and with a loss of offsite power following turbine trip. With offsite power available, the reactor coolant pumps continue to circulate coolant through the steam generators, maximizing the Reactor Coolant System cooldown. With a loss of offsite power, the response of mitigating systems is delayed.

BASES

APPLICABLE SAFETY ANALYSES (continued)

Significant single failures considered include:

1) failure of an MSIV or MSCV to close; 2) failure of a feedwater control or isolation valve to close; 3) failure of a diesel generator; and, 4) failure of auxiliary feedwater pump runout protection.

The MSIVs serve only a safety function and remain open during power operation. These valves operate under the following situations:

a. A HELB inside containment. In order to maximize the mass and energy release into containment, the analysis assumes that the MSCV in the affected steam generator remains open. For this accident scenario, steam is discharged into containment from all steam generators until the remaining MSIVs close. After MSIV closure, steam is discharged into containment only from the affected steam generator and from the residual steam in the main steam header downstream of the closed MSIVs in the unaffected loops. Closure of the MSIVs isolates the break from the unaffected steam generators.

b. A break outside of containment and upstream from the MSIVs. This case is not a containment pressurization concern. The uncontrolled blowdown of more than one steam generator must be prevented to limit the potential for uncontrolled RCS cooldown and positive reactivity addition. Closure of the MSIVs isolates the break and limits the blowdown to a single steam generator.

c. A break downstream of the MSIVs. This case will be isolated by the closure of the MSIVs.

d. Following a steam generator tube rupture. In this case, closure of the MSIVs isolates the ruptured steam generator from the intact steam generators to minimize radiological releases.

BASES

APPLICABLE SAFETY ANALYSES (continued)

e. The MSIVs are also utilized during other events such as a feedwater line break. This event is less limiting so far as MSIV OPERABILITY is concerned.

The MSIVs satisfy Criterion 3 of 10 CFR 50.36.

LCO

This LCO requires that four MSIVs and four MSCVs in the steam lines be OPERABLE. The MSIVs are considered OPERABLE when the isolation times are within limits, and they close on an isolation actuation signal. The MSCVs are considered OPERABLE when inspections and testing required by the Inservice Test Program are completed at the specified FREQUENCY.

This LCO provides assurance that the MSIVs and MSCVs will perform their design safety function to mitigate the consequences of accidents that could result in offsite exposures comparable to the 10 CFR 100 (Ref. 4) limits or the NRC staff approved licensing basis.

APPLICABILITY

The MSIVs and MSCVs must be OPERABLE in MODE 1, and in MODES 2 and 3 except when MSIVs are closed. These are the conditions when there is significant mass and energy in the RCS and steam generators. When the MSIVs are closed, they are already performing the safety function.

In MODE 4, the steam generator energy is low and the potential for and consequences of an SLB are significantly reduced.

In MODE 5 or 6, the steam generators do not contain much energy because their temperature is below the boiling point of water; therefore, the MSIVs are not required for isolation of potential high energy secondary system pipe breaks in these MODES.

BASES

ACTIONS

A.1

With one or more MSCVs inoperable, action must be taken to restore OPERABLE status within 48 hours. In this condition, the MSIVs in the other three steam lines must close to prevent the blowdown of more than one SG following an SLB upstream of an MSIV. Having more than one MSCV inoperable will not increase the consequences of an SLB upstream of an MSIV because only the MSCV associated with the faulted SG needs to function to mitigate the failure of an MSIV associated with any of the other SGs. Additionally, an inoperable MSCV does not affect the consequences of an SLB downstream of the MSIV.

The 48 hour Completion Time is acceptable because of the following: all MSIVs are Operable, there is a low probability of the failure of an MSIV during the 48 hour period that one or more MSCVs are inoperable; and, there is a low probability of an accident that would require a closure of the MSCVs or MSIVs during this period.

B.1, B.2 and B.3

If the MSCVs cannot be restored to OPERABLE status within 48 hours, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in MODE 2 within 6 hours and all MSIVs must be closed within 14 hours. The Completion Times are reasonable, based on operating experience, to reach MODE 2 and to close the MSIVs or complete a plant cooldown to MODE 4 in an orderly manner and without challenging unit systems.

If an inoperable MSCVs cannot be restored to OPERABLE status within the specified Completion Time, then all MSIVs must be verified to be closed on a periodic basis while the plant is in MODE 2 or 3. This is necessary to ensure that the assumptions in the safety analysis remain valid. The 7 day Completion Time is reasonable, based on engineering judgment, in view of MSIV status indications available in the control room, and other administrative controls, to ensure that these valves are in the closed position.

BASES

ACTIONS (continued)

C.1

With one MSIV inoperable in MODE 1, action must be taken to restore OPERABLE status within 48 hours. Some repairs to the MSIV can be made with the unit hot. The 48 hour Completion Time is acceptable because the four OPERABLE MSCVs prevent the blowdown of more than one SG following an SLB upstream of the MSIV even if more than one MSIV fails to close. Additionally, there is a low probability of the failure of an MSCV during the 48 hour period that the MSIV is inoperable; and, there is a low probability of an accident that would require a closure of the MSIVs occurring during this time period.

The 48 hour Completion Time is greater than that normally allowed for containment isolation valves because the MSIVs are valves that isolate a closed system penetrating containment. These valves differ from most other containment isolation valves in that the closed system provides an additional means for containment isolation.

D.1

If the MSIV cannot be restored to OPERABLE status within 48 hours, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in MODE 2 within 6 hours and Condition E would be entered. The Completion Times are reasonable, based on operating experience, to reach MODE 2 and to close the MSIVs in an orderly manner and without challenging unit systems.

E.1 and E.2

Condition E is modified by a Note indicating that separate Condition entry is allowed for each MSIV.

Since the MSIVs are required to be OPERABLE in MODES 2 and 3, the inoperable MSIVs may either be restored to OPERABLE status or closed. When closed, the MSIVs are already in the position required by the assumptions in the safety analysis.

BASES

ACTIONS

E.1 and E.2 (continued)

The 8 hour Completion Time is reasonable, based on operating experience, to close the MSIVs after reaching MODE 2 or complete a plant cooldown to MODE 4 in an orderly manner and without challenging unit systems.

For inoperable MSIVs that cannot be restored to OPERABLE status within the specified Completion Time, but are closed, the inoperable MSIVs must be verified on a periodic basis to be closed. This is necessary to ensure that the assumptions in the safety analysis remain valid. The 7 day Completion Time is reasonable, based on engineering judgment, in view of MSIV status indications available in the control room, and other administrative controls, to ensure that these valves are in the closed position.

F.1 and F.2

If one MSIV is inoperable when one or more MSCVs are inoperable, then more than one SG may blowdown following an SLB upstream of an MSIV and the plant is outside of the analysis assumptions. The plant remains within the analysis assumptions for an SLB downstream of an MSIV although the ability to tolerate the failure of a second MSIV is lost. In this condition, all MSCVs must be restored to OPERABLE status or all MSIVs must be restored to OPERABLE status within 8 hours.

The 8 hour Completion Time is acceptable because of the low probability of an accident that would require a closure of the MSCVs or MSIVs during this time period. The 8 hour Completion Time is greater than that normally allowed for containment isolation valves because the MSIVs are valves that isolate a closed system penetrating containment. These valves differ from most other containment isolation valves in that the closed system provides an additional means for containment isolation.

G.1 and G.2

If the MSIVs or MSCVs cannot be restored to OPERABLE status or are not closed within the associated Completion Time, the unit must be placed in a MODE in which the LCO does not apply. To

BASES

achieve this status, the unit must be placed at least in MODE 3 within 6 hours, and in MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from MODE 2 conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.2.1

This SR verifies that MSIV closure time is ≤ 5.0 seconds on an actual or simulated actuation signal. The MSIV closure time is assumed in the accident and containment analyses. This Surveillance is normally performed upon returning the unit to operation following a refueling outage. The MSIVs are not tested at power because even a part stroke causes a turbine trip and valve closure. As the MSIVs are not tested at power, they are exempt from the ASME Code, Section XI (Ref. 5), requirements during operation in MODE 1 or 2.

The Frequency is in accordance with the Inservice Testing Program. The Frequency for valve closure time is based on the refueling cycle. Operating experience has shown that these components usually pass the Surveillance when performed at this Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

This test is conducted in MODE 3 with the unit at operating temperature and pressure, as discussed in Reference 5. This SR is modified by a Note that allows entry into and operation in MODE 3 prior to performing the SR. This allows a delay of testing until MODE 3, to establish conditions consistent with those under which the acceptance criterion was generated.

SR 3.7.2.2

Each MSCV must be inspected to ensure that it closes properly with no steam flow as is required to perform its design function. This ensures that the safety analysis assumptions are met. The Frequency of this SR is based on Inservice Testing Program requirements and corresponds to the expected refueling cycle.

BASES

REFERENCES (continued)

REFERENCES

1. FSAR, Section 10.2.
2. FSAR, Section 6.
3. FSAR, Section 14.
4. 10 CFR 100.11.
5. ASME, Boiler and Pressure Vessel Code, Section XI.

B 3.7 PLANT SYSTEMS

B 3.7.3 Main Boiler Feedpump Discharge Valves (MBFPDVs), Main Feedwater Regulation Valves (MBFRVs) and MBFRV Low Flow Bypass Valves

BASES

BACKGROUND

The MBFPDVs isolate main feedwater (MFW) flow to the secondary side of the steam generators following a high energy line break (HELB). The safety related function of the MBFRVs is to provide the second isolation of MFW flow to the secondary side of the steam generators following an HELB. Closure of the two MBFPDVs or four MBFRVs and four MBFRV low flow bypass valves terminates flow to the steam generators. The consequences of events occurring in the main steam lines or in the MFW lines downstream from the MBFPDVs will be mitigated by their closure. Closure of the MBFPDVs or MBFRVs and MBFRV low flow bypass valves, effectively terminates the addition of feedwater to an affected steam generator, limiting the mass and energy release for steam line breaks (SLBs) or FWLBs inside containment, and reducing the cooldown effects for SLBs.

In the event of a secondary side pipe rupture inside containment, either the MBFPDVs or MBFRVs and MBFRV low flow bypass valves limit the quantity of high energy fluid that enters containment through the break, and provide a pressure boundary for the controlled addition of auxiliary feedwater (AFW) to the intact loops.

One MBFPDV is located on the discharge of each of the two Main Boiler Feedpumps (MBFPs), and one MBFRV and MBFRV low flow bypass valve, is located on each of the four MFW lines, outside but close to containment. The MFIVs and MFRVs are located upstream of the AFW injection point so that AFW may be supplied to the steam generators following MBFPDV or MBFRV closure. The piping volume from these valves to the steam generators must be accounted for in calculating mass and energy releases, and refilled prior to AFW reaching the steam generator following either an SLB or FWLB.

The two MBFPDVs, four MBFRVs and four MBFRV low flow bypass valves will close on receipt of an ESFAS Safety Injection signal. An ESFAS Tavg-Low coincident with reactor trip will close the

BASES

BACKGROUND (Continued)

four MBFRVs and four MBFRV low flow bypass valves. A Steam Generator Hi-Hi level trip will close the MBFPDV and MBFRVs and MBFRV low flow bypass valves associated with the affected SG. They may also be closed manually. In addition to the two MBFPDVs, four MBFRVs and four MBFRV low flow bypass valves, a check valve outside containment is available. The check valve isolates the feedwater line to prevent blowdown of a SG if main or auxiliary feedwater pressure are lost.

A description of the MBFPDVs and MBFRVs is found in the FSAR, Section 10.2 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The design basis of the MBFPDVs and MBFRVs is established by the analyses for the large SLB. Closure of the MBFPDVs, MBFRVs and MBFRV low flow bypass valves, may also be relied on to terminate an SLB for core response analysis and excess feedwater event upon the receipt of a steam generator water level – high high or a feedwater isolation signal. Feedwater isolation also occurs as a result of any safety injection signal.
Failure of an MBFPDV in conjunction with the failure of an MBFRV or MBFRV low flow bypass valve to close following an SLB can result in additional mass and energy being delivered to the steam generators, contributing to cooldown. This failure also results in additional mass and energy releases following an SLB or FWLB event.

The MBFPDVs and MBFRVs satisfy Criterion 3 of 10 CFR 50.36.

LCO

This LCO ensures that the MBFPDVs, MBFRVs and MBFRV low flow bypass valves will isolate MFW flow to the steam generators, following a main steam line break.

This LCO requires that two MBFPDVs, four MBFRVs and four MBFRV low flow bypass valves be OPERABLE. The MBFPDVs, MBFRVs and

BASES

LCO (continued)

MBFRV low flow bypass valves are considered OPERABLE when isolation times are within limits and they close on an isolation actuation signal.

Failure to meet the LCO requirements can result in additional mass and energy being released to containment following an SLB or FWLB inside containment. A feedwater isolation signal on a steam generator water level - high high signal and this function is relied on to terminate an excess feedwater flow event; therefore, failure to meet the LCO may result in the introduction of water into the main steam lines.

APPLICABILITY

The MBFPDVs, MBFRVs and MBFRV bypass valves must be OPERABLE whenever there is significant mass and energy in the Reactor Coolant System and steam generators. This ensures that, in the event of an HELB, a single failure cannot result in the blowdown of more than one steam generator. In MODES 1, 2, and 3, the MBFPDVs, MBFRVs and MBFRV bypass valves are required to be OPERABLE to limit the amount of available fluid that could be added to containment in the case of a secondary system pipe break inside containment. When the valves are closed and de-activated or isolated by a closed manual valve, they are already performing their safety function. A de-activated motor operated valve is considered to be a manual valve.

In MODES 4, 5, and 6, steam generator energy is low. Therefore, the MBFPDVs, MBFRVs and MBFRV bypass valves are normally closed since MFW is not required.

ACTIONS

The ACTIONS table is modified by a Note indicating that separate Condition entry is allowed for each valve.

BASES

ACTIONS (continued)

A.1 and A.2

With one MFPDV in one or both flow paths inoperable, action must be taken to restore the affected valves to OPERABLE status, or to close or isolate inoperable affected valves within 72 hours. When these valves are closed or isolated, they are performing their required safety function.

The 72 hour Completion Time takes into account the redundancy afforded by the remaining OPERABLE valves, the MBFP trip function, and the low probability of an event occurring during this time period that would require isolation of the MFW flow paths. The 72 hour Completion Time is reasonable, based on industry operating experience.

Inoperable MBFPDVs that are closed or isolated must be verified on a periodic basis that they are closed or isolated. This is necessary to ensure that the assumptions in the safety analysis remain valid. The 7 day Completion Time is reasonable, based on engineering judgment, in view of valve status indications available in the control room, and other administrative controls, to ensure that these valves are closed or isolated.

B.1 and B.2

With one MBFRV in one or more flow paths inoperable, action must be taken to restore the affected valves to OPERABLE status, or to close or isolate inoperable affected valves within 72 hours. When these valves are closed or isolated, they are performing their required safety function.

The 72 hour Completion Time takes into account the redundancy afforded by the remaining OPERABLE valves and the low probability of an event occurring during this time period that would require isolation of the MFW flow paths. The 72 hour Completion Time is reasonable, based on industry operating experience.

Inoperable MBFRVs, that are closed or isolated, must be verified on a periodic basis that they are closed or isolated. This is necessary to ensure that the assumptions in the safety analysis

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BASES

ACTIONS

B.1 and B.2 (continued)

remain valid. The 7 day Completion Time is reasonable, based on engineering judgment, in view of other administrative controls to ensure that the valves are closed or isolated.

C.1 and C.2

With one MBFRV low flow bypass valve in one or more flow paths inoperable, action must be taken to restore the affected valves to OPERABLE status, or to close or isolate inoperable affected valves within 72 hours. When these valves are closed or isolated, they are performing their required safety function.

The 72 hour Completion Time takes into account the redundancy afforded by the remaining OPERABLE valves and the low probability of an event occurring during this time period that would require isolation of the MFW flow paths. The 72 hour Completion Time is reasonable, based on industry operating experience.

Inoperable associated bypass valves that are closed or isolated must be verified on a periodic basis that they are closed or isolated. This is necessary to ensure that the assumptions in the safety analysis remain valid. The 7 day Completion Time is reasonable, based on engineering judgment, in view of the administrative controls that ensure that these valves are closed or isolated.

D.1

With two inoperable valves in series in the same flow path, there may be no redundant system to operate automatically and perform the required safety function. Under these conditions, affected valves in each flow path must be restored to OPERABLE status, or the affected flow path isolated within 8 hours. This action returns the system to the condition where at least one valve in each flow path is performing the required safety function. The 8 hour Completion Time is reasonable, based on operating experience, to complete the actions required to close the MBFPDV or MBFRV, or otherwise isolate the affected flow path.

BASES

ACTIONS (continued)

E.1 and E.2

If the MBFPDV(s), MBFRV(s), and MBFRV bypass valve(s) cannot be restored to OPERABLE status, or closed, or isolated within the associated Completion Time, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 4 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.3.1

This SR verifies that the closure time of each MBFPDV(s), MBFRV(s), and MBFRV bypass valves is within required limits on an actual or simulated actuation signal. The closure times are assumed in the accident and containment analyses. The acceptance criteria for this SR do not include the 2 second delay associated with the ESFAS activation signal. This Surveillance is normally performed upon returning the unit to operation following a refueling outage. These valves can not be tested at power because valve closure or even a part stroke exercise increases the risk of a valve closure and MBFP trip. This is consistent with the ASME Code, Section XI (Ref. 2), quarterly stroke requirements during operation in MODES 1 and 2.

The Frequency for this SR is in accordance with the Inservice Testing Program. The required Frequency for valve closure is based on the refueling cycle. Operating experience has shown that these components usually pass the Surveillance when performed at the required Frequency.

BASES

REFERENCES

1. FSAR, Section 10.2.
2. ASME, Boiler and Pressure Vessel Code, Section XI.

B 3.7 PLANT SYSTEMS

B 3.7.4 Atmospheric Dump Valves (ADVs)

BASES

BACKGROUND

The ADVs provide a method for cooling the unit to residual heat removal (RHR) entry conditions should the preferred heat sink via the Steam Bypass System (High Pressure Steam Dump) to the condenser not be available, as discussed in the FSAR, Section 10.2 (Ref. 1). This is done in conjunction with the Auxiliary Feedwater System providing cooling water from the condensate storage tank (CST). The ADVs may also be required to meet the design cooldown rate during a normal cooldown when steam pressure drops too low for maintenance of a vacuum in the condenser to permit use of the High Pressure Steam Dump System.

One ADV line for each of the four steam generators is provided. Each ADV line consists of one ADV and an associated manually operated block valve.

The block valves are upstream of the ADVs to permit testing and maintenance at power, and to provide an alternate means of isolation. The ADVs are equipped with pneumatic controllers to permit control of the cooldown rate.

The ADVs are provided with a pressurized gas supply of bottled nitrogen that is needed to support manual operation of the atmospheric dump valves. The nitrogen supply is sized to provide the sufficient pressurized gas to operate the ADVs for the time required for Reactor Coolant System cooldown to RHR entry conditions.

A description of the ADVs is found in Reference 1.

APPLICABLE SAFETY ANALYSES

The design basis of the ADVs is established by the capability to cool the unit to RHR entry conditions. The total relief capacity of the four ADVs is approximately 10% of the

BASES

APPLICABLE SAFETY ANALYSES (continued)

rated steam flow. This is adequate to cool the unit to RHR entry conditions with only one steam generator and one ADV, utilizing the cooling water supply available in the CST.

In the accident analysis presented in Reference 1, the ADVs are assumed to be used by the operator to cool down the unit to RHR entry conditions for accidents accompanied by a loss of offsite power. Prior to operator actions to cool down the unit, the main steam safety valves (MSSVs) are assumed to operate automatically to relieve steam and maintain the steam generator pressure below the design value. For the recovery from a steam generator tube rupture (SGTR) event, the operator is also required to perform a limited cooldown to establish adequate subcooling as a necessary step to terminate the primary to secondary break flow into the ruptured steam generator. The time required to terminate the primary to secondary break flow for an SGTR is more critical than the time required to cool down to RHR conditions for this event and also for other accidents. Thus, the SGTR is the limiting event for the ADVs. The requirement that 3 of the 4 ADVs must be OPERABLE is established to ensure that at least one ADV line is available under local control to conduct a plant cooldown following an event in which one steam generator becomes unavailable due to the event (i.e., SGTR or SLB), accompanied by a single, active failure of a second ADV line on an unaffected steam generator.

The ADVs are equipped with block valves in the event an ADV spuriously fails open or fails to close during use.

The ADVs satisfy Criterion 3 of 10 CFR 50.36.

LCO

Three of the four ADV lines are required to be OPERABLE. One ADV line is required from each of three steam generators to ensure that at least one ADV line is available to conduct a unit cooldown following an SGTR, in which one steam generator becomes unavailable, accompanied by a single, active failure of a second ADV line on an unaffected steam generator. The block valves must be OPERABLE to isolate a failed open ADV line. A closed block

BASES

LCO (continued)

valve does not render it or its ADV line inoperable because operator action time to open the block valve is supported in the accident analysis.

Failure to meet the LCO can result in the inability to cool the unit to RHR entry conditions following an event in which the condenser is unavailable for use with the Turbine Steam Bypass System (High Pressure Steam Dump).

An ADV is considered OPERABLE when it is capable of providing controlled relief of the main steam flow and capable of fully opening and closing on demand (either remotely or under local control).

APPLICABILITY

In MODES 1, 2, and 3, and in MODE 4, when a steam generator is being relied upon for heat removal, the ADVs are required to be OPERABLE.

In MODE 5 or 6, an SGTR is not a credible event.

ACTIONS

A.1

With one required ADV line inoperable, action must be taken to restore OPERABLE status within 30 days. The 30 day Completion Time allows for the redundant capability afforded by the remaining OPERABLE ADV lines. Specifically, with one of the three required ADVs inoperable, at least one ADV line is available to conduct a plant cooldown following an event in which one steam generator becomes unavailable due to the event (i.e., SGTR or SLB), accompanied by a single, active failure of a second ADV line on an unaffected steam generator. Required Action A.1 is modified by a Note indicating that LCO 3.0.4 does not apply.

BASES

ACTIONS (continued)

B.1

With two or more required ADV lines inoperable, action must be taken to restore all but one ADV line to OPERABLE status. Since the block valve can be closed to isolate an ADV, some repairs may be possible with the unit at power. The 24 hour Completion Time is reasonable to repair inoperable ADV lines, based on the availability of the Steam Bypass System (HP Steam Dump) and MSSVs, and the low probability of an event occurring during this period that would require the ADV lines.

C.1 and C.2

If the ADV lines cannot be restored to OPERABLE status within the associated Completion Time, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 4, without reliance upon steam generator for heat removal, within 18 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.4.1

To perform a controlled cooldown of the RCS, the ADVs must be able to be opened either remotely or locally and throttled through their full range. This SR ensures that the ADVs are tested through a full control cycle at least once per fuel cycle. Performance of inservice testing or use of an ADV during a unit cooldown may satisfy this requirement. Operating experience has shown that these components usually pass the Surveillance when performed at the specified Frequency and, therefore, is acceptable from a reliability standpoint.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.4.2

The function of the block valve is to isolate a failed open ADV. Cycling the block valve both closed and open demonstrates its capability to perform this function. Performance of inservice testing or use of the block valve during unit cooldown may satisfy this requirement. Operating experience has shown that these components usually pass the Surveillance when performed at the specified Frequency and, therefore, is acceptable from a reliability standpoint.

REFERENCES

1. FSAR, Section 10.2.

B 3.7 PLANT SYSTEMS

B 3.7.5 Auxiliary Feedwater (AFW) System

BASES

BACKGROUND

The AFW System automatically supplies feedwater to the steam generators to remove decay heat from the Reactor Coolant System upon the loss of normal feedwater supply. The AFW pumps take suction from the condensate storage tank (CST) (LCO 3.7.6) and pump to the steam generator secondary side that connect to the main feedwater (MFW) piping outside containment. The steam generators function as a heat sink for core decay heat. The heat load is dissipated by releasing steam to the atmosphere from the steam generators via the main steam safety valves (MSSVs) (LCO 3.7.1) or atmospheric dump valves (LCO 3.7.4). If the main condenser is available, steam may be released via the steam bypass (High Pressure Steam Dump) valves and recirculated to the CST.

The AFW System consists of two motor driven AFW pumps and one steam turbine driven pump configured into three trains. FSAR Section 10.2 (Ref. 1) describes this configuration as two pumping loops using two different types of motive power to the pumps. One auxiliary feedwater loop utilizes a steam turbine driven pump and the other utilizes two motor driven pumps. Technical specifications describe this configuration as three trains because each motor driven pump provides 100% of AFW flow capacity, and, depending on steam conditions, the turbine driven pump capacity approaches 200% of the required capacity to the steam generators, as assumed in the accident analysis. The pumps are equipped with independent recirculation lines to prevent pump operation against a closed system. Each motor driven AFW pump is powered from an independent power supply and feeds two steam generators. The steam turbine driven AFW pump receives steam from two main steam lines upstream of the main steam isolation valves. Each of the steam feed lines will supply 100% of the requirements of the turbine driven AFW pump.

The AFW System is capable of supplying feedwater to the steam generators during normal unit startup, shutdown, and hot standby conditions.

BASES

BACKGROUND (Continued)

The turbine driven AFW pump supplies a common header capable of feeding all steam generators. Each of the steam generators can also be supplied by one of the two motor driven AFW pumps. Any of the three pumps at full flow is sufficient to remove decay heat and cool the unit to residual heat removal (RHR) entry conditions. Thus, the requirement for diversity in motive power sources for the AFW System is met.

The AFW System is designed to supply sufficient water to the steam generator(s) to remove decay heat with steam generator pressure at the setpoint of the MSSVs. Subsequently, the AFW System supplies sufficient water to cool the unit to RHR entry conditions, with steam released through the ADVs.

The motor driven pumps are actuated by any one of the following:

1) Low-low level in any steam generator;

2) Loss of voltage (Non SI blackout) on 480 VAC bus 2A/3A (starts AFW Pump 31) and loss of voltage (Non SI blackout) on 480 VAC bus 6A (starts AFW Pump 33);

3) Safety Injection signal;

4) Auto trip of either main boiler feed pump;

5) Manual actuation from the Control Room; and

6) Manual actuation locally at the pump room.

The steam turbine driven pump is actuated by any one of the following:

1) Low-low level in two of the four steam generators;

2) Loss of voltage (Non SI blackout) on 480 VAC busses 2A/3A or 6A;

3) Manual actuation from the Control Room; and

BASES

BACKGROUND (Continued)

4) Manual actuation locally at the pump room.

The steam driven AFW pump must be throttled manually in order to bring the unit up to speed after a start signal. In addition, the steam driven pump discharge flow control valves must be manually opened as necessary to provide adequate auxiliary feedwater flow.

The AFW System is discussed in the FSAR, Section 10.2 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The AFW System mitigates the consequences of any event with loss of normal feedwater.

The design basis of the AFW System is to supply water to the steam generator to remove decay heat and other residual heat by delivering at least the minimum required flow rate to the steam generators at pressures corresponding to the lowest steam generator safety valve set pressure plus accumulation.

In addition, the AFW System must supply enough makeup water to replace steam generator secondary inventory lost as the unit cools to MODE 4 conditions. Sufficient AFW System flow must also be available to account for flow losses such as pump recirculation and line breaks.

The limiting events that require the AFW System are as follows:

a. small break loss of coolant accident;

b. loss of AC sources; and

c. loss of feedwater.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The AFW turbine driven pump actuates automatically when required to ensure an adequate feedwater supply to the steam generators is available during loss of power. Power operated valves are provided for each AFW line to control the AFW flow to each steam generator.

The AFW System satisfies the requirements of Criterion 3 of 10 CFR 50.36.

LCO

This LCO provides assurance that the AFW System will perform its design safety function to mitigate the consequences of events that could result in overpressurization of the reactor coolant pressure boundary. Three independent AFW pumps are required to be OPERABLE to ensure the capability to maintian the plant in hot shutdown with a loss of offsite power and a single failure. This is accomplished by powering two of the pumps from independent emergency buses. The third AFW pump is powered by a steam driven turbine supplied with steam from a source that is not isolated by closure of the MSIVs.

The AFW System is configured into three trains. The AFW System is considered OPERABLE when the components and flow paths required to provide redundant AFW flow to the steam generators are OPERABLE. This requires that the two motor driven AFW pumps be OPERABLE, each supplying AFW to two separate steam generators. The turbine driven AFW pump is required to be OPERABLE with steam supplies from each of two main steam lines upstream of the MSIVs, and shall be capable of supplying AFW to all of the steam generators. The piping, valves, instrumentation, and controls in the required flow paths also are required to be OPERABLE.

The LCO is modified by a Note indicating that one AFW train, which includes a motor driven pump, is required to be OPERABLE in MODE 4. The motor driven AFW pump required to be OPERABLE in Mode 4 must be capable of supporting the SG being credited as the redundant decay heat removal path in accordance with LCO 3.4.6, RCS Loops - MODE 4. This requirement ensures the ability to

BASES

LCO (continued)

maintain the required level in the SG (and decay heat removal capacity) during extended periods in Mode 4 with or without offsite power. Requiring only one OPERABLE AFW pump is acceptable because of the reduced heat removal requirements and short period of time in MODE 4 during which the AFW is required and the insufficient steam available in MODE 4 to power the turbine driven AFW pump.

APPLICABILITY

In MODES 1, 2, and 3, the AFW System is required to be OPERABLE in the event that it is called upon to function when the MFW is lost. In addition, the AFW System is required to supply enough makeup water to replace the steam generator secondary inventory needed to achieve and maintain MODE 4 conditions.

In MODE 4, a motor driven AFW pump may be needed to support heat removal via the steam generators.

In MODE 5 or 6, the steam generators are not normally used for heat removal, and the AFW System is not required.

ACTIONS

A.1

If one of the two steam supplies to the turbine driven AFW train is inoperable, action must be taken to restore OPERABLE status within 7 days. The 7 day Completion Time is reasonable, based on the following reasons:

a. The redundant OPERABLE steam supply to the turbine driven AFW pump;

b. The availability of redundant OPERABLE motor driven AFW pumps; and

c. The low probability of an event occurring that requires the inoperable steam supply to the turbine driven AFW pump.

BASES

ACTIONS

A.1 (continued)

The second Completion Time for Required Action A.1 establishes a limit on the maximum time allowed for any combination of Conditions to be inoperable during any continuous failure to meet this LCO.

The 10 day Completion Time provides a limitation time allowed in this specified Condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The AND connector between 7 days and 10 days dictates that both Completion Times apply simultaneously, and the more restrictive must be met.

B.1

With one of the required AFW trains (pump or flow path) inoperable in MODE 1, 2, or 3 for reasons other than Condition A, action must be taken to restore OPERABLE status within 72 hours. This Condition includes the loss of two steam supply lines to the turbine driven AFW pump. The 72 hour Completion Time is reasonable, based on redundant capabilities afforded by the AFW System, time needed for repairs, and the low probability of a DBA occurring during this time period.

The second Completion Time for Required Action B.1 establishes a limit on the maximum time allowed for any combination of Conditions to be inoperable during any continuous failure to meet this LCO.

The 10 day Completion Time provides a limitation time allowed in this specified Condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The AND connector between 72 hours and 10 days dictates that both Completion Times apply simultaneously, and the more restrictive must be met.

C.1 and C.2

When Required Action A.1 or B.1 cannot be completed within the required Completion Time, or if two AFW trains are inoperable in MODE 1, 2, or 3, the unit must be placed in a MODE in which the

BASES

ACTIONS

C.1 and C.2 (continued)

LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 4 within 18 hours.

The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

In MODE 4 with two AFW trains inoperable, operation is allowed to continue because only one motor driven pump AFW train is required in accordance with the Note that modifies the LCO. Although not required, the unit may continue to cool down and initiate RHR.

D.1

If all three AFW trains are inoperable in MODE 1, 2, or 3, the unit is in a seriously degraded condition with no safety related means for conducting a cooldown, and only limited means for conducting a cooldown with nonsafety related equipment. In such a condition, the unit should not be perturbed by any action, including a power change, that might result in a trip. The seriousness of this condition requires that action be started immediately to restore one AFW train to OPERABLE status.

Required Action D.1 is modified by a Note indicating that all required MODE changes or power reductions are suspended until one AFW train is restored to OPERABLE status. In this case, LCO 3.0.3 is not applicable because it could force the unit into a less safe condition.

E.1

In MODE 4, either the reactor coolant pumps or the RHR loops can be used to provide forced circulation. This is addressed in LCO 3.4.6, "RCS Loops - MODE 4." With one required AFW train inoperable, action must be taken to immediately restore the inoperable train to OPERABLE status. The immediate Completion Time is consistent with LCO 3.4.6.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.5.1

Verifying the correct alignment for manual, power operated, and automatic valves in the AFW System water and steam supply flow paths provides assurance that the proper flow paths will exist for AFW operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since they are verified to be in the correct position prior to locking, sealing, or securing. This SR also does not apply to valves that cannot be inadvertently misaligned, such as check valves. This Surveillance does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct position.

The 31 day Frequency is based on engineering judgment, is consistent with the procedural controls governing valve operation, and ensures correct valve positions.

This SR is modified by a Note that states the SR is not required in MODE 4. Not performing this SR in MODE 4 is acceptable for the following reasons: AFW pumps are typically operated intermittently to keep the SGs filled when in MODE 4, the decay heat load is low; an RHR loop is required to be OPERABLE as the primary method of decay heat removal in Mode 4; and, the SG is required to be maintained at a level that ensures a significant inventory is available as a heat sink before the AFW pump is required to refill the SG. These factors ensure that a significant amount of time would be available to complete any valve realignments needed to refill a SG when in Mode 4.

SR 3.7.5.2

Verifying that each AFW pump's developed head at the flow test point is greater than or equal to the required developed head ensures that AFW pump performance has not degraded during the cycle. Flow and differential head are normal tests of centrigufal pump performance required by Section XI of the ASME Code (Ref 2). Because it is undesirable to introduce cold AFW into the steam generators while they are operating, this testing is performed on recirculation flow. This test confirms one point

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.5.2 (continued)

on the pump design curve and is indicative of overall performance. Such inservice tests confirm component OPERABILITY, trend performance, and detect incipient failures by indicating abnormal performance. Performance of inservice testing discussed in the ASME Code, Section XI (Ref. 2) (only required at 3 month intervals) satisfies this requirement.

This SR is modified by a Note indicating that the SR should be deferred until suitable test conditions are established. This deferral is required because there is insufficient steam pressure to perform the test when SG pressure is < 600 psig.

SR 3.7.5.3

This SR verifies that AFW can be delivered to the appropriate steam generator in the event of any accident or transient that generates an ESFAS, by demonstrating that each automatic valve in the flow path actuates to its correct position on an actual or simulated actuation signal. This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. The 24 month Frequency is acceptable based on operating experience and the design reliability of the equipment.

This SR is modified by a Note that states the SR is not required in MODE 4. In MODE 4, the required AFW train is operated as necessary to maintain SG water level.

SR 3.7.5.4

This SR verifies that the AFW pumps will start in the event of any accident or transient that generates an ESFAS by demonstrating that each AFW pump starts automatically on an actual or simulated actuation signal in MODES 1, 2, and 3. In

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.5.4 (continued)

MODE 4, the required pump is operated as necessary and the autostart function is not required. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power.

This SR is modified by two Notes. Note 1 indicates that the SR be deferred until suitable test conditions are established. This deferral allows the test to be performed at rated conditions. Note 2 states that the SR is not required in MODE 4. In MODE 4, the required pump is operated as necessary to maintian SG water level and the autostart function is not required. In MODE 4, the heat removal requirements would be less providing more time for operator action to manually start the required AFW pump.

REFERENCES

1. FSAR, Section 10.2.

2. ASME, Boiler and Pressure Vessel Code, Section XI.

B 3.7 PLANT SYSTEMS

B 3.7.6 Condensate Storage Tank (CST)

BASES

BACKGROUND

The CST provides a safety grade source of water to the steam generators for removing decay and sensible heat from the Reactor Coolant System (RCS). The CST provides a passive flow of water, by gravity, to the Auxiliary Feedwater (AFW) System (LCO 3.7.5). The steam produced is released to the atmosphere by the main steam safety valves or the atmospheric dump valves. The AFW steam driven pump operates with a continuous recirculation to the CST. The motor driven AFW pumps have recirculation controllers that recirculate flow to the CST, as necessary, to maintain a minimum required AFW pump flow.

When the main steam isolation valves are open, the preferred means of heat removal is to discharge steam to the condenser by the nonsafety grade path of the steam bypass (High Pressure Steam Dump) valves. The condensed steam is returned to the CST by the condensate pump. This has the advantage of conserving condensate while minimizing releases to the environment.

Because the CST is a principal component in removing residual heat from the RCS, it is designed to withstand earthquakes and other natural phenomena. The CST is designed to Seismic Class I to ensure availability of the auxiliary feedwater supply. Auxiliary feedwater is also available from city water.

The condensate makeup system connects the 600,000 gallon capacity condensate storage tank to the main condenser. The condensate makeup system automatically supplies makeup water from the CST to the condenser if there is a low level in the condenser hotwell. Redundant, Category I, isolating valves will close the condenser makeup when the condensate storage tank level decreases to 360,000 gallons to reserve the required volume of condensate available to the auxiliary feedwater pumps sufficient to hold the plant at hot shutdown for 24 hours following a trip at full power.

To ensure CST pressure is maintained within its design limits while limiting the amount of air in contact with the condensate,

BASES

BACKGROUND (continued)

two Category I, 100% capacity breather valves are installed on the dome of the CST. CST venting is required for the CST to perform both its normal and emergency function. The venting function can be met by either of the CST breather valves or equivalent venting capacity.

A description of the CST is found in the FSAR, Section 10.2 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The CST provides cooling water to remove decay heat and the minimum amount of water in the condensate storage tank is the amount needed to maintain the plant for 24 hours at hot shutdown following a trip from full power. When the condensate storage tank supply is exhausted, city water will be used.

The CST satisfies Criteria 2 and 3 of 10 CFR 50.36.

LCO

To satisfy accident analysis assumptions, the CST must contain sufficient cooling water to remove decay heat while in MODE 3 for 24 hours following a reactor trip from 102% RTP. In doing this, it must retain sufficient water to ensure adequate net positive suction head for the AFW pumps during cooldown, as well as account for any losses from the steam driven AFW pump turbine. When the condensate storage tank supply is exhausted, city water will be used.

The CST level required is equivalent to a total volume of ≥ 360,000, which is based on holding the unit in MODE 3 for 24 hours. This basis is established in Reference 1. The CST total volume includes allowances for instrument accuracy and the unuseable volume in the CST.

The OPERABILITY of the CST is determined by maintaining the tank level at or above the minimum required level.

BASES

APPLICABILITY

In MODES 1, 2, and 3, and in MODE 4, when steam generator is being relied upon for heat removal, the CST is required to be OPERABLE.

In MODE 5 or 6, the CST is not required because the AFW System is not required.

ACTIONS

A.1 and A.2

If the CST is not OPERABLE, the OPERABILITY of the backup supply (city water) should be verified by administrative means immediately and once every 12 hours thereafter. OPERABILITY of the backup auxiliary feedwater supply means that LCO 3.7.7, City Water, is met. The CST must be restored to OPERABLE status within 7 days. The immediate Completion Time for verification of the OPERABILITY of the backup water supply ensures that Condition B is entered immediately if both the CST and City Water are inoperable. The 7 day Completion Time for restoration of the CST is reasonable, based on an OPERABLE backup water supply being available, and the low probability of an event occurring during this time period requiring the CST.

B.1 and B.2

If the CST cannot be restored to OPERABLE status within the associated Completion Time, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 4, without reliance on the steam generator for heat removal, within 18 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

If Condition B is entered when both the CST and City Water are not Operable, Conditions and Required Actions for LCO 3.7.5, Auxiliary Feedwater System, may be appropriate.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.6.1

This SR verifies that the CST contains the required volume of cooling water. The 12 hour Frequency is based on operating experience and the need for operator awareness of unit evolutions that may affect the CST inventory between checks. Also, the 12 hour Frequency is considered adequate in view of other indications in the control room, including alarms, to alert the operator to abnormal deviations in the CST level.

REFERENCES

1. FSAR, Section 10.2.

B 3.7 PLANT SYSTEMS

B 3.7.7 City Water (CW)

BASES

BACKGROUND

City Water is the backup to the Condensate Storage Tank (CST) as a water supply for the Auxiliary Feedwater System. The CST, the preferred source of water for the Steam Generators (SGs), is capable of holding up to 600,000 gallons and is sized to meet the normal operating and maintenance needs of the main steam system. LCO 3.7.6, Condensate Storage Tank, requires that a minimum water level is maintained in the CST that is sufficient to remove residual heat for 24 hours at hot shutdown conditions following a trip from full power. Only when the CST supply is exhausted, will city water be used to supply the Auxiliary Feedwater System.

When the main steam isolation valves are open, the preferred means of heat removal from the RCS is to discharge steam to the condenser via the non-safety grade turbine steam bypass valves (High Pressure Steam Dump) with water supplied from the CST to the SGs using the AFW System. The condensed steam is returned to the CST by the condensate pump. This configuration conserves condensate and minimizes releases to the environment. The CST is the preferred source of water for the SGs.

When the CST supply is exhausted, city water is used to supply the Auxiliary Feedwater System for decay heat removal and plant cooldown. CW, although aligned to the IP3 site, is normally isolated from the AFW pump suctions.

The City Water System includes the site city water header consisting of the 1.5 million gallon city water storage tank and the connection to the offsite water supply. A description of the CW system is found in FSAR, Section 10 (Ref. 1).

APPLICABLE SAFETY ANALYSES

CW can be used to provide cooling water to remove decay heat and to cool down the unit following all events in the accident analysis as discussed in the FSAR, Chapters 6 and 14 (Refs. 2

APPLICABLE SAFETY ANALYSES (continued)

and 3, respectively); however, CW is used only when the CST is not available or depleted.

CW satisfies Criterion 3 of 10 CFR 50.36.

LCO

This LCO requires that the CW supply header is aligned to the AFW pump suction headers except for the onsite isolation valves, which are normally closed. The City Water Storage Tank is not required to contain a specific volume of water; however, the static head on CW supply from the CW storage tank is used to indicate that the CW supply header and CW System are aligned to the IP3 site and available for use.

The OPERABILITY of the CW is determined by maintaining the supply header pressure at or above the minimum required pressure and periodic verification that the required lineups can be established.

APPLICABILITY

City Water is required to be OPERABLE in MODES 1, 2, and 3, and in MODE 4, when a steam generator is being relied upon for heat removal. In MODE 5 or 6, CW is not required because the SGs are not normally used to remove decay heat when in these MODES.

ACTIONS

A.1 and A.2

If the CW header pressure is not within limits or system lineups are not as required, CW cannot be assumed to be available if needed as a backup water source for the CST. With CW not available, OPERABILITY of the CST must be verified by administrative means immediately and once every 12 hours thereafter. Operability of the CST means that LCO 3.7.6, Condensate Storage Tank, is met. The immediate Completion Time for verification of the OPERABILITY of the CST ensures that Condition B is entered immediately if both the CST and City Water

BASES

ACTIONS

A.1 and A.2 (continued)

are inoperable. This ensures that either the CST or CW is available for decay heat removal and to support a plant cooldown.

CW must be restored to OPERABLE status within 7 days because CW is assumed to be available to supply the Auxiliary Feedwater System when the CST supply is exhausted. The 7 day Completion Time for restoration of CW is acceptable because the CST is OPERABLE and the low probability of an event requiring CW during the 7 day Completion Time.

B.1 and B.2

If CW cannot be restored to OPERABLE within the Completion Time, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 4, without reliance on the steam generator for heat removal, within 18 hours. The Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

If Condition B is entered when both the CST and City Water are not Operable, Conditions and Required Actions for LCO 3.7.5, Auxiliary Feedwater System, may be appropriate.

SURVEILLANCE REQUIREMENTS

SR 3.7.7.1

This SR verifies that CW header pressure is greater than 30 psig which provides a high degree of assurance that the offsite CW supply is available to the site and properly aligned. Operating experience has demonstrated that CW header pressure decays rapidly due to normal onsite consumption if the offsite supply is not properly aligned or pressurized. The 12 hour Frequency provides a high degree of assurance of rapid identification of the inoperability of CW.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.7.2

This SR verifies that the valve that isolates Unit 3 from the site city water supply and the city water storage tank is open. This isolation valve, CT-49, in the IP1 Utility Tunnel, is also identified as valve FP-1227. This SR may be performed by Consolidated Edison personnel. The 31 day Frequency is acceptable because the valve is sealed open and because periodic verification provided by SR 3.7.7.1 provides a high degree of assurance that the valve is positioned properly.

SR 3.7.7.3

This SR verifies the ability to cycle each valve between CW and the AFW pump suction. These are the only valves required to operate to align CW to the AFW pump suction. The testing requirements and Frequency for this SR are in accordance with the Inservice Testing Program.

REFERENCES

1. FSAR, Chapter 10.
2. FSAR, Chapter 6.
3. FSAR, Chapter 14.

B 3.7 PLANT SYSTEMS

B 3.7.8 Component Cooling Water (CCW) System

BASES

BACKGROUND

The Component Cooling Water (CCW) System is a closed-loop cooling system that provides cooling water for systems and components important to safety that are located in the Primary Auxiliary Building, the Fuel Storage Building, and the Containment Building. The CCW System transfers its heat load to the Service Water System via CCW heat exchangers. The Service Water System is a once through cooling system that transfers its heat load to the ultimate heat sink, the Hudson River.

The CCW System provides a heat sink for the removal of process and operating heat from safety related components during a Design Basis Accident (DBA) or transient. During normal operation, the CCW System also provides this function for various nonessential components including the spent fuel storage pool. The CCW System serves as a barrier to the release of radioactive byproducts between potentially radioactive systems and the Service Water System, and thus to the environment.

The CCW System consists of three pumps and two heat exchangers. These components are divided into two independent, full capacity cooling loops with each loop consisting of one pump and a heat exchanger. The third CCW pump can be aligned to replace the pump in either loop. Each of the three CCW pumps is powered from a separate safeguards power train.

The CCW loops are cross connected during normal and emergency operation; however, the cooling loads are divided between the two loops so that each loop is capable of supplying the necessary service to support continued containment sump and core recirculation following a LOCA while supplying normal loads. Operating CCW loops cross-connected allows use of either CCW heat exchanger to cool all normal and post accident heat loads. Any service water system pump can be used to support either or both CCW heat exchangers. Isolation valves allow each loop to be isolated and operated as an independent component cooling loop. This configuration facilitates detection of radioactivity

BASES

BACKGROUND (continued)

entering the loop for leak detection or isolation of a piping or component failure during an event. A surge tank in each loop ensures that sufficient net positive suction head is available.

CCW pumps continue to operate following a safety injection signal without loss of offsite power (LOOP); however, CCW pumps are stripped and must be started as needed following any event that includes a LOOP. Note that the CCW pumps are not re-started during the injection phase; therefore, the water volume of the CCW system must act as a heat sink during the injection phase when the CCW pumps are not running, This is acceptable even though safety injection pump bearings are cooled by CCW because the cooling water is circulated by a booster pump directly connected to the injection pump motor shaft. During the injection phase, the Recirculation Pumps are cooled by the Auxilliary Component Cooling Water pumps, which are not governed by this LCO.

Additional information on the design and operation of the system, along with a list of the components served, is presented in the FSAR, Section 9.3 (Ref. 1). The principal safety related function of the CCW System is the removal of decay heat from the reactor via the Residual Heat Removal (RHR) System. This may be during a normal or post accident cooldown and shutdown.

APPLICABLE SAFETY ANALYSES

The design basis of the CCW System is for one CCW loop to remove the post loss of coolant accident (LOCA) heat load from the containment sump during the recirculation phase. Any one of the three CCW pumps in conjunction with any one of the two CCW heat exchangers is sufficient to accommodate the normal and post accident heat load if the CCW system is operated as two cross connected loops. Either CCW pump in conjunction with either CCW heat exchanger or the third CCW pump in conjunction with either associated CCW heat exchanger is sufficient if the CCW loops are isolated.

BASES

APPLICABLE SAFETY ANALYSES (continued)

Because the component cooling pumps do not run during the injection phase if the event is accompanied by a loss of offsite power, the water volume of the CCW system is used as a heat sink. This heat load causes a temperature rise of approximately 7°F per hour in the component cooling water with no credit taken for the water volume in the surge tank. With a minimum initial CCW temperature of 110°F at the start of the accident, 6 hours are available before the cooling water temperature reaches 150°F; 10 hours is available before reaching 180°F. Evaluations of the heat removal capability of the CCW system are contained in References 2 and 3.

The CCW System is designed to perform its function with a single failure of any active component, assuming a loss of offsite power.

The CCW System also functions to cool the unit from RHR entry conditions (T_{avg} < 350°F), to MODE 5 (T_{avg} < 200°F), during normal and post accident operations. The time required to cool from 350°F to 200°F is a function of the CCW and RHR flow rate, service water flow rate and UHS temperature. One CCW loop is sufficient to remove decay heat during subsequent operations with T_{avg} < 200°F. This assumes a maximum service water temperature of 95°F occurring simultaneously with the maximum heat loads on the system.

The CCW System satisfies Criterion 3 of 10 CFR 50.36.

LCO

The CCW loops are independent of each other to the degree that each has separate controls and power supplies and the operation of one does not depend on the other. In the event of a DBA, one CCW loop is required to provide the minimum heat removal capability assumed in the safety analysis for the systems to which it supplies cooling water. To ensure this requirement is met, two loops of CCW must be OPERABLE. At least one CCW loop will operate during the recirculation phase assuming the worst case single active failure occurs coincident with a loss of offsite power.

BASES

LCO (continued)

A CCW loop consists of any of the three CCW pumps in conjunction with a CCW heat exchanger.

A CCW loop is considered OPERABLE when:

a. The pump and associated surge tank are OPERABLE; and

b. The associated piping, valves, heat exchanger, and instrumentation and controls required to perform the safety related function are OPERABLE.

The isolation of CCW from components or systems may render those components or systems inoperable but does not affect the OPERABILITY of the CCW System.

Note that the auxiliary component cooling water pumps support the Containment Recirculation pumps only and are governed by LCO 3.5.2, ECCS - Operating.

APPLICABILITY

In MODES 1, 2, 3, and 4, the CCW System is a normally operating system, which must be prepared to perform its post accident safety functions, primarily RCS heat removal, which is achieved by cooling the RHR heat exchanger.

In MODE 5 or 6, the OPERABILITY requirements of the CCW System are determined by the systems it supports.

ACTIONS

A.1

Required Action A.1 is modified by a Note indicating that the applicable Conditions and Required Actions of LCO 3.4.6, "RCS Loops – MODE 4," be entered if an inoperable CCW loop results in an inoperable RHR loop. This is an exception to LCO 3.0.6 and ensures the proper actions are taken for these components.

BASES

ACTIONS

A.1 (continued)

If one CCW loop is inoperable, action must be taken to restore OPERABLE status within 72 hours. In this Condition, the remaining OPERABLE CCW loop is adequate to perform the heat removal function. The 72 hour Completion Time is reasonable, based on the redundant capabilities afforded by the OPERABLE loop, and the low probability of a DBA occurring during this period.

B.1 and B.2

If the CCW loop cannot be restored to OPERABLE status within the associated Completion Time, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours and in MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.8.1

This SR is modified by a Note indicating that the isolation of the CCW flow to individual components may render those components inoperable but does not affect the OPERABILITY of the CCW System.

Verifying the correct alignment for manual, power operated, and automatic valves in the CCW flow path provides assurance that the proper flow paths exist for CCW operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these valves are verified to be in the correct position prior to locking, sealing, or securing. Valves located inside containment are considered to be locked. This SR also does not apply to valves that cannot be inadvertently misaligned, such as check valves. This Surveillance does not require any testing or valve manipulation; rather, it involves verification

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.8.1 (continued)

that those valves capable of being mispositioned are in the correct position. Valves that are throttled are verified by verification of required flow.

The 92 day Frequency is based on engineering judgment, is consistent with the procedural controls governing valve operation, and ensures correct valve positions.

SR 3.7.8.2

This SR verifies proper automatic operation of the CCW valves on an actual or simulated actuation signal. The CCW System is a normally operating system that cannot be fully actuated as part of routine testing during normal operation. This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

SR 3.7.8.3

This SR verifies proper automatic operation of the CCW pumps on an actual or simulated actuation signal. The CCW System is a normally operating system that cannot be fully actuated as part of routine testing during normal operation. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

BASES

REFERENCES

1. FSAR, Section 9.3.
2. FSAR, Section 6.2.
3. WCAP-12313, "Safety Evaluation for an Ultimate Heat Sink Temperature Increased to 95° at IP-3."

B 3.7 PLANT SYSTEMS

B 3.7.9 Service Water System (SW)

BASES

BACKGROUND

The SW provides a heat sink for the removal of process and operating heat from safety related components during a Design Basis Accident (DBA) or transient. During normal operation, and a normal shutdown, the SW also provides this function for various safety related and nonsafety related components. The safety related function is covered by this LCO.

The SW consists of two separate, 100% capacity, safety related, cooling water headers. Each header is supplied by three pumps and includes the piping up to and including the isolation valves on individual components cooled by the SW. Each of the 6 SW pumps is equipped with rotary strainers and isolation valves.

SW heat loads are designated as either essential or nonessential. The essential SW heat loads are those which must be supplied with cooling water immediately in the event of a LOCA and/or loss of offsite power (LOOP). Examples of essential loads are the emergency diesel generators (EDGs), containment fan cooler units (FCUs) and control room air conditioning system (CRACS). The nonessential SW heat loads are those which are required only following the switch over to the recirculation phase following a postulated LOCA. Examples of nonessential loads are the component cooling water (CCW) heat exchangers.

The FCUs are connected in parrallel to the essential SW header. Normal SW flow to the FCUs is controlled by TCV-1103. Required ESFAS flow to all five FCUs is initiated when either of the redundant SW to FCU ESFAS valves (TCV-1104 or TCV-1105) opens automatically in response to an ESFAS actuation signal.

The EDGs are connected in parrallel to the essential SW header. Required ESFAS flow to all three EDGs is initiated when either of the redundant SW to EDG ESFAS valves (FCV-1176 or FCV-1176A) opens automatically in response to an ESFAS actuation which starts the EDGs.

BASES

BACKGROUND (continued)

The CRACS are connected in parrallel to the essential SW header. Required ESFAS flow to both CRACS is provided continuously because the redundant SW to CRACS valves (TCV-1310/1311 and TCV-1312/1313) have been modified to provide the required flow at all times.

Either of the two SW headers can be aligned to supply the essential heat loads or the nonessential SW heat loads. Both the essential and nonessential SW headers are operated to support normal plant operation and the plant response to accidents and transients. The SW pumps associated with the SW header designated as the essential header will start automatically. The SW pumps associated with the SW header designated as the nonessential header must be manually started when required following a LOCA.

The essential SW heat loads can be cooled by any two of the three service water pumps on the essential header. The nonessential SW heat loads can be cooled by any one of the three service water pumps on the nonessential header. To ensure adequate flow to the essential header, the essential and nonessential headers may be cross connected only as necessary while swapping the essential SW header with the non essential SW header.

Service water pump suctions are located below the mean sea level in the Hudson River, the ultimate heat sink. This configuration ensures adequate submergence of the SW pump suctions.

Additional information about the design and operation of the SW, along with a list of the components served, is presented in the FSAR, Section 9.6, (Ref. 1). The principal safety related function of the SW is the removal of decay heat from the reactor via the CCW System.

BASES

APPLICABLE SAFETY ANALYSES

The design basis of the SW is as follows: post accident essential SW heat loads can be cooled by any two of the three service water pumps on the designated essential header; and, post accident nonessential SW heat loads can be cooled by any one of the three service water pumps on the designated nonessential header. With the minimum number of pumps operating, the essential and nonessential headers of the SW have the required capacity to remove core decay heat following a design basis LOCA as discussed in References 1, 2 and 3. This prevents the containment sump fluid from increasing in temperature during the recirculation phase following a LOCA and provides for a gradual reduction in the temperature of this fluid as it is supplied to the Reactor Coolant System by the ECCS pumps. The Service Water System was designed to fulfill required safety functions while sustaining: (a) the single failure of any active component used during the injection phase of a postulated LOCA with or without a LOOP, or (b) the single failure of any active or passive component used during the long-term recirculation phase with or without a LOOP.

The operating modes of the IP3 SW are as follows: a) normal mode; b) post-LOCA injection mode; and, c) post-LOCA recirculation mode. The postulated failure conditions of the SW must include consideration of the limiting case for each operating mode of the system which are as follows:

a. Loss of the 10 inch turbine building service water supply header during normal operation and a seismic event;
b. Loss of instrument air, during the post-LOCA injection phase concurrent with single active component failure.
c. Loss of a SW pump on both the essential and nonessential headers (resulting from an EDG failure) during the post-LOCA recirculation phase.

The SW, in conjunction with the CCW System, also cools the unit from residual heat removal (RHR) entry conditions to MODE 5 during normal and post accident operations. The time required for this evolution is a function of CCW and RHR system flow, SW flow and UHS temperature. This assumes a maximum SW temperature

BASES

APPLICABLE SAFETY ANALYSES (continued)

of 95°F occurring simultaneously with maximum heat loads on the system (Ref. 3).

The SW satisfies Criterion 3 of 10 CFR 50.36.

LCO

Three of the three SW pumps associated with the SW header designated as the essential header; and, two of the three SW pumps associated with the SW header designated as the nonessential header must be OPERABLE to provide the required redundancy to ensure that the system functions to remove post accident heat loads, while sustaining: (a) the single failure of any active component used during the injection phase of a postulated LOCA with or without a LOOP, or (b) the single failure of any active or passive component used during the long-term recirculation phase with or without a LOOP.

An SW header is considered OPERABLE during MODES 1, 2, 3, and 4 when:

a. The required number of pumps, consistent with the header's designation as the essential or nonessential header, are OPERABLE; and

b. The essential and nonessential headers are isolated from each other by at least one closed valve except as specified by NOTE 2 to the ACTIONS;

c. The associated piping, valves, instrumentation and controls required to perform the safety related function are OPERABLE.

The SW to FCU valves (TCV-1104 or TCV-1105) and SW to EDG valves (FCV-1176 or FCV-1176A) are OPERABLE when they open automatically in response to ESFAS actuation signal or are blocked open.

BASES

APPLICABILITY

In MODES 1, 2, 3, and 4, the SW is a normally operating system that is required to support the OPERABILITY of the equipment serviced by the SW and required to be OPERABLE in these MODES.

In MODES 5 and 6, the OPERABILITY requirements of the SW are determined by the systems it supports.

ACTIONS

The ACTIONS are modified by two Notes. Note 1 specifies that separate condition entry is allowed for the SW header designated as essential and for the SW header designated as nonessential. This allows completely separate re-entry into any Condition for the essential SW header and the nonessential SW header. Separate condition entry includes separate tracking of Completion Times based on this re-entry. This is acceptable because the accident analysis assumptions regarding the available number of SW pumps on the essential and nonessential SW headers are independent.

Note 2 specifies that LCO 3.0.3 is not applicable for 8 hours while swapping the essential SW header with the nonessential SW header but only if LCO 3.7.9 will be met after the essential and non-essential header are swapped. This means that the essential and nonessential SW headers may be cross-connected for up to 8 hours during transfer of the designated essential SW header to the alternate SW header. This is acceptable because the transfer is performed infrequently (i.e., approximately every 90 days) and the low probability of an event while the headers are cross connected.

<u>A.1</u>

If one of the three required SW pumps on the essential SW header is inoperable, three Operable pumps must be restored to the essential SW header within 72 hours. Likewise, if one of the two required SW pumps on nonessential SW header is inoperable, the header must be restored so that there are two Operable pumps for the nonessential SW header within 72 hours. With one required SW pump inoperable on either or both SW headers, the remaining OPERABLE SW pumps are adequate to perform the heat removal function. However, the overall reliability is reduced because a

BASES

ACTIONS

A.1 (contdinued)

single failure in an OPERABLE SW pump could result in loss of SW function. The 72 hour Completion Time is based on the redundant capabilities afforded by the OPERABLE pump(s) in the same header, and the low probability of a DBA occurring during this time period.

B.1 and C.1

Required ESFAS flow to all three EDGs is initiated when either of the redundant SW to EDG valves (FCV-1176 or FCV-1176A) opens automatically in response to an ESFAS actuation which starts the EDGs. Similarly, required ESFAS flow to all five FCUs is initiated when either of the redundant SW to FCU valves (TCV-1104 or TCV-1105) opens automatically in response to an ESFAS actuation signal. The SW to FCU valves and SW to EDG valves are OPERABLE when they open automatically in response to an ESFAS actuation signal or are blocked open.

If one of the redundant SW to EDG valves is inoperable, a single failure of the redundant valve could result in the failure of all three EDGs shortly after the initiation of an event. If one of the redundant SW to FCU valves is inoperable, a single failure of the redundant valve could result in the failure of all five FCUs. Therefore, a Completion Time of 12 hours is established to restore the required redundancy.

A 12 hour Completion Time is acceptable for the SW to EDG valves because SW to the EDGs is still available and the low probability of an event with a loss of offsite power during this period. A 12 hour Completion Time is acceptable for the SW to FCU valves because SW to the FCUs is still available, the avialability of Containment Spray, and the low probability of an event during this period.

If both SW to EDG valves or both SW to FCU valves are inoperable, entry into LCO 3.0.3 is required.

BASES

ACTIONS (continued)

D.1 and D.2

If more than one required SW pump in either the essential or the nonessential header is inoperable; or, if the flow path associated with either header is not capable of performing its safety function (e.g., both SW to EDG valves or both SW to FCU valves are inoperable), then the unit must be placed in a MODE in which the LCO does not apply.

Additionally, if an SW header cannot be restored to OPERABLE status within the associated Completion Time, the unit must be placed in a MODE in which the LCO does not apply.

To achieve the required status, the unit must be placed in at least MODE 3 within 6 hours and in MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.9.1

This SR is modified by a Note indicating that the isolation of the SW components or systems may render those components inoperable, but does not affect the OPERABILITY of the SW.

Verifying the correct alignment for manual, power operated, and automatic valves in the SW flow path provides assurance that the proper flow paths exist for SW operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since they are verified to be in the correct position prior to being locked, sealed, or secured. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.9.1 (continued)

The 92 day Frequency is based on engineering judgment, is consistent with the procedural controls governing valve operation, and ensures correct valve positions.

SR 3.7.9.2

This SR verifies proper automatic operation of the SW valves on an actual or simulated actuation signal. The SW is a normally operating system that cannot be fully actuated as part of normal testing. This Surveillance is not required for valves that are locked, sealed, or otherwise secured in the required position under administrative controls. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

SR 3.7.9.3

This SR verifies proper automatic operation of the SW pumps on an actual or simulated actuation signal. The SW is a normally operating system that cannot be fully actuated as part of normal testing during normal operation. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

BASES

REFERENCES

1. FSAR, Section 9.6.
2. FSAR, Section 6.2.
3. WCAP-12313, "Safety Evaluation for an Ultimate Heat Sink Temperature Increase to 95°F at Indian Point 3."

B 3.7 PLANT SYSTEMS

B 3.7.10 Ultimate Heat Sink (UHS)

BASES

BACKGROUND

The UHS provides a heat sink for processing and operating heat from safety related components during a transient or accident, as well as during normal operation. This is done by utilizing the Service Water System (SWS) and the Component Cooling Water (CCW) System.

The ultimate heat sink for IP3 is the Hudson River. The UHS and supporting structures are capable of providing sufficient cooling for thirty days and are sufficient to:

(a) Support simultaneous safe shutdown and cooldown of both operating nuclear units at the Indian Point site and maintain them in a safe condition, and

(b) In the event of an accident in one unit, support required response to that accident and permit simultaneous safe shutdown and cooldown of the remaining unit and maintain them in a safe shutdown condition.

The ultimate heat sink is capable of withstanding the effects of the most severe natural phenomena associated with the Indian Point site, other site related events and a single failure of man-made structural features.

The two principal functions of the UHS are the dissipation of residual heat after reactor shutdown, and dissipation of residual heat after an accident.

APPLICABLE SAFETY ANALYSES

The UHS is the sink for heat removed from the reactor core following all accidents and anticipated operational occurrences in which the unit is cooled down and placed on residual heat removal (RHR) operation. Because IP3 uses the UHS as the normal heat sink for condenser cooling via the Circulating

BASES

APPLICABLE SAFETY ANALYSES (continued)

Water System, unit operation at full power is its maximum heat load. Its maximum post accident heat load occurs shortly after a design basis loss of coolant accident (LOCA). Near this time, the unit switches from injection to recirculation and the containment cooling systems and containment recirculation system are required to remove the core decay heat.

The operating limits are based on conservative heat transfer analyses for the worst case LOCA. Reference 1 provides the details of the assumptions used in the analysis, which include worst expected meteorological conditions, conservative uncertainties when calculating decay heat, and worst case single active failure (e.g., single failure of a manmade structure). The UHS meets Regulatory Guide 1.27 (Ref.3), which requires a 30 day supply of cooling water in the UHS.

The UHS satisfies Criterion 3 of 10 CFR 50.36.

LCO

The UHS is required to be OPERABLE and is considered OPERABLE if it contains water at or below the maximum temperature that would allow the SWS to operate for at least 30 days following the design basis LOCA without the loss of net positive suction head (NPSH), and without exceeding the maximum design temperature of the equipment served by the SWS. To meet this condition, the UHS temperature must not exceed 95°F.

APPLICABILITY

In MODES 1, 2, 3, and 4, the UHS is required to support the OPERABILITY of the equipment serviced by the UHS and required to be OPERABLE in these MODES.

In MODE 5 or 6, the OPERABILITY requirements of the UHS are determined by the systems it supports.

BASES

ACTIONS

A.1

If UHS temperature > 95°F, the UHS temperature must be verified to be ≤ 95°F within 7 hours. The 7 hour Completion Time allows for the dissipation of tidal effects that can cause river water temperature transients that may temporarily increase localized UHS temperature.

B.1 and B.2

If UHS temerature does not return to ≤ 95°F within the associated Completion Time, or if the UHS is inoperable for reasons other than Condition A, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours and in MODE 5 within 36 hours.

The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.10.1

This SR verifies that the SWS is available to cool the CCW System to at least its maximum design temperature with the maximum accident or normal design heat loads for 30 days following a Design Basis Accident. The 24 hour Frequency is based on operating experience related to trending of the parameter variations during the applicable MODES. This SR verifies that the average water temperature of the UHS is ≤ 95°F.

BASES

REFERENCES

1. FSAR, Section 9.6.

2. WCAP-12313, "Safety Evaluation For An Ultimate Heat Sink Temperature Increase To 95°F At Indian Point Unit 3"

3. Regulatory Guide 1.27.

B 3.7 PLANT SYSTEMS

B 3.7.11 Control Room Ventilation System (CRVS)

BASES

BACKGROUND

The CRVS provides a protected environment from which operators can control the unit following an uncontrolled release of radioactivity, chemicals, or toxic gas.

The Control Room Ventilation System consists of the following equipment: a single filter unit consisting of two roughing filters, two high efficiency particulate air (HEPA) filters; two activated charcoal adsorbers for removal of gaseous activity (principally iodines); two 100% capacity filter booster fans; and, a single duct system including dampers, controls and associated accessories to provide for three different air flow configurations. The air-conditioning units associated with the CRVS are governed by LCO 3.7.12, "Control Room Air Conditioning System (CRACS)."

The CRVS is divided into two trains with each train consisting of a filter booster fan and the associated inlet damper and the following components which are common to both trains: the control room filter unit, damper A (filter unit bypass for outside air makeup to the Control Room), damper B (filter unit inlet for outside air makeup to the Control Room), damper C (filter unit inlet for reticulated air), and the toilet and locker room exhaust fan. The two filter booster fans (F 31 and F 32) are powered from safeguards power trains 5A (EDG 33) and 6A (EDG 32), respectively. Each of the automatic dampers that are common to both trains is positioned in the fail-safe position (open or closed) by either of the redundant actuation channels.

The CRVS is an emergency system, parts of which operate during normal unit operations.

The three different CRVS air flow configurations are as follows:

a) <u>Normal operation</u> consists of approximately 85% (8500 cfm) unfiltered recirculated flow driven by the air-conditioning fans and approximately 15% (1500 cfm) unfiltered outside air makeup;

BASES

BACKGROUND (Continued)

b) <u>Incident mode with outside air makeup</u> (i.e. 10% incident mode) consists of approximately 87% (9250 cfm) unfiltered recirculated flow driven by the two safety related air-conditioning fans, at least 10% (> 1000 cfm) filtered recirculated flow driven by either one of the two filter booster fans and approximately 2.5% to 4.0% (250 to 400 cfm) filtered outside air makeup;

c) <u>Incident mode with no outside air makeup</u> (i.e. 100% incident mode) consists of 85% (9100 cfm) unfiltered reticulated flow driven by the two safety related air-conditioning fans, approximately 15% filtered recirculated flow driven by either one of the two filter booster fans and no outside air makeup.

Note that the required recirculation rates are demonstrated with surveillance tests conducted with the air conditioning system (CRACS) operating. An inoperable CRACS fan will affect the flow balance of tdhe CRVS due to interconnected ductwork. Therefore, if the fan associated with one of the air-conditioning units governed by LCO 3.7.12 is inoperable, Conditions in both LCO 3.7.11, Control Room Ventilation System, and LCO 3.7.12, Control Room Air Conditioning System (CRACS), will apply.

Incident mode with outside air makeup is the preferred method of operation during any radiological event because it provides outside air for pressurization of the Control Room. Calculations indicate that very low volumes of outside air makeup will maintain the Control Room at a slight positive pressure. Nevertheless, due to the difficulty of adjusting and maintaining the flow dampers to provide a low flow, it was determined that the damper should be adjusted to provide a flow of approximately 250 cfm (2.5% outside air makeup). However, a higher volume of outside air makeup to the Control Room increase the thyroid dose to the operators during an accident. Therefore, the Control Room dose assessment assumes a filtered outside air makeup of approximately 400 cfm (4.0% outside air makeup).

On a Safety Injection signal or high radiation in the Control Room (Radiation Monitor R-1), the CRVS will actuate to the <u>incident</u>

BASES

BACKGROUND (Continued)

mode with outside air makeup (i.e. 10% incident mode). This will cause one of the two filters booster fans to start, the locker room exhaust fan to stop, and CRVS dampers to open or close as necessary to filter all incoming outside air and direct approximately 10% of the recirculated air through the filter unit. In the event that the first booster fan fails to start, the second booster fan will start after a predetermined time delay.

If for any reason it is required or desired to operate with 100% recirculated air (e.g., toxic gas condition is identified), the CRVS can be placed in the incident mode with no outside air makeup (i.e. 100% incident mode) by remote manually operated switches. The Firestat detectors will also initiate 100% incident mode in the CRVS.

The control room is continuously monitored by radiation and toxic gas detectors. On a Safety Injection signal or high radiation in the Control Room (Radiation Monitor R-1), will cause actuation of the emergency radiation state of the CRVS (i.e., incident mode with outside air makeup (i.e. 10% incident mode)).

The CRVS does not actuate automatically in response to toxic gases. Separate chlorine, ammonia and oxygen probes are provided to detect the presence of these gases in the outside air intake. Additionally, monitors in the Control Room will detect low oxygen levels and high levels of chlorine and ammonia. The CRVS may be placed in the incident mode with no outside air makeup (i.e. 100% incident mode) to respond to these conditions. Instrumentation for toxic gas monitoring is governed by the IP3 Technical Requirements Manual (TRM) (Ref. 4). Generally, the manually initiated actions of the toxic gas isolation state are more restrictive, and will override the actions of the emergency radiation state.

A single train will create a slight positive pressure in the control room. The CRVS operation in maintaining the control room habitable is discussed in the FSAR, Section 9.9 (Ref. 1).

The CRVS is designed in accordance with Seismic Category I requirements.

BASES

BACKGROUND (Continued)

The CRVS is designed to maintain the control room environment for 30 days of continuous occupancy after a Design Basis Accident (DBA) without exceeding a 5 rem whole body dose or 30 rem to the thyroid.

APPLICABLE SAFETY ANALYSES

The CRVS components are arranged in redundant, safety related ventilation trains. The location of components and ducting within the control building envelope ensures an adequate supply of filtered air to all areas requiring access. The CRVS provides airborne radiological protection for the control room operators, as demonstrated by the control room accident dose analyses for the most limiting design basis accident (i.e., DBA LOCA) fission product release presented in the FSAR, Chapter 14 (Ref. 2).

Radiation monitor R-1 is not required for the Operability of the Control Room Ventilation System because control room isolation is initiated by the safety injection signal in MODES 1, 2, 3, 4, and control room isolation is not required for maintaining radiation exposure within General Design Criteria 19 limits following a fuel handling accident or gas-decay-tank rupture.

The worst case active failure of a redundant component of the CRVS, assuming a loss of offsite power, does not impair the ability of the system to perform its design function. However, the original CRVS design was not required to meet single failure criteria and, although upgraded from the original design, CRVS does not satisfy all requirements in IEEE-279 for single failure tolerance. Note that the required recirculation rates are demonstrated with surveillance tests conducted with the air conditioning system (CRACS) operating. An inoperable CRACS fan will affect the flow balance of tdhe CRVS due to interconnected ductwork. Therefore, if the fan associated with one of the air-conditioning units governed by LCO 3.7.12 is inoperable, Conditions in both LCO 3.7.11, Control Room Ventilation System,

BASES

APPLICABLE SAFETY ANALYSES (continued)

and LCO 3.7.12, Control Room Air Conditioning System (CRACS), will apply.

The CRVS satisfies Criterion 3 of 10 CFR 50.36.

LCO

Two CRVS trains are required to be OPERABLE to ensure that at least one is available. Total system failure could result in exceeding a dose of 5 rem whole body or 30 rem to the thyroid of the control room operator in the event of a large radioactive release.

The CRVS is considered OPERABLE when the individual components necessary to limit operator exposure are OPERABLE in both trains. A CRVS train is OPERABLE when the associated:

a. A Filter booster fan and an air-conditioning unit fan powered from the same safeguards power train are OPERABLE;

b. HEPA filters and charcoal adsorbers are not excessively restricting flow, and are capable of performing their filtration functions; and

c. Ductwork, valves, and dampers are OPERABLE or in the incident mode, and air circulation can be maintained.

In addition, the control room boundary must be maintained, including the integrity of the walls, floors, ceilings, ductwork, and access doors.

Instrumentation for toxic gas monitoring is governed by the IP3 Technical Requirements Manual (TRM) (Ref. 4) and is not included in the LCO. Note that the required recirculation rates are demonstrated with surveillance tests conducted with the air conditioning system (CRACS) operating. An inoperable CRACS fan will affect the flow balance of tdhe CRVS due to interconnected ductwork. Therefore, if the fan associated with one of the air-conditioning units governed by LCO 3.7.12 is inoperable, Conditions in both LCO 3.7.11, Control Room Ventilation System,

BASES

LCO (continued)

and LCO 3.7.12, Control Room Air Conditioning System (CRACS), will apply.

APPLICABILITY

In MODES 1, 2, 3, 4 CRVS must be OPERABLE to limit operator exposure during and following a DBA.

The CRVS is not required in MODE 5 or 6, or during movement of irradiated fuel assemblies and core alterations because analysis indicates that isolation of the control room is not required for maintaining radiation exposure within acceptable limits following a fuel handling accident or gas decay tank rupture.

Administrative controls address the role of the CRVS in maintaining control room habitability following an event at Indian Point Unit 2.

ACTIONS

A.1

When one CRVS train is inoperable, action must be taken to restore OPERABLE status within 7 days. In this Condition, the remaining OPERABLE CRVS train is adequate to perform the control room protection function. However, the overall reliability is reduced because a single failure in the OPERABLE CRVS train could result in loss of CRVS function. The 7 day Completion Time is based on the low probability of a DBA occurring during this time period, and ability of the remaining train to provide the required capability.

B.1

When neither CRVS train is Operable, action must be taken to restore at least one train to OPERABLE status within 72 hours. The 72 hour Completion Time is acceptable because of the low probability of a DBA occurring during this time period.

BASES

ACTIONS (continued)

C.1 and C.2

If Required Actions A.1 or B.1 are not met within the required Completion Time, the unit must be placed in a MODE that minimizes accident risk. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.11.1

Standby systems should be checked periodically to ensure that they function properly. As the environment and normal operating conditions on this system are not too severe, testing each train once every month provides an adequate check of this system. Note that a CRVS train includes both the filter booster fan and an air-conditioning unit fan powered from the same safeguards power train. The 31 day Frequency is based on the reliability of the equipment and the two train redundancy availability.

SR 3.7.11.2

This SR verifies that the required CRVS testing is performed in accordance with the Ventilation Filter Testing Program (VFTP). The CRVS filter tests are in accordance with the sections of Regulatory Guide 1.52 (Ref. 3) identified in the VFTP. The VFTP includes testing the performance of the HEPA filter, charcoal adsorber efficiency, minimum flow rate, and the physical properties of the activated charcoal. Specific test Frequencies and additional information are discussed in detail in the VFTP.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.7.11.3

This SR verifies that each CRVS train starts and operates on an actual or simulated actuation signal. The Frequency of 24 months is based on operating experience which has demonstrated this Frequency provides a high degree of assurance that the booster fans will operate and dampers actuate to the correct position when required.

SR 3.7.11.4

This SR verifies the integrity of the control room enclosure, and the assumed inleakage rates of the potentially contaminated air. The control room positive pressure, with respect to potentially contaminated adjacent areas, is periodically tested to verify proper functioning of the CRVS. During the operation in the incident mode with outside air makeup (i.e. 10% incident mode), the CRVS is designed to maintain the control room at a slight positive pressure with respect to adjacent areas in order to prevent unfiltered inleakage. The CRVS is designed to maintain this positive pressure with very low volumes of outside air makeup. Due to the difficulty of adjusting and maintaining the flow dampers to provide a low flow, it was determined that the damper should be adjusted to provide a flow of approximately 250 cfm (2.5% outside air makeup). Note that the higher the volume of outside air makeup to the Control Room, the higher the thyroid dose to the operators during an accident. The acceptance criteria of 400 cfm (4.0% outside air makeup) is the volume used in the Control Room dose assessment.

The SR Frequency of 24 months on a staggered test basis is acceptable because operating experience has demonstrated that the control room boundary is not normally disturbed. Staggered testing is acceptable because the SR is primarily a verification of Control Room integrity because fan operation is tested elsewhere.

BASES

REFERENCES

1. FSAR, Section 9.9.
2. FSAR, Chapter 14.
3. Regulatory Guide 1.52, Rev. 2.
4. IP3 Technical Requirements Manual.

B 3.7 PLANT SYSTEMS

B 3.7.12 Control Room Air Conditioning System (CRACS)

BASES

BACKGROUND

The CRACS provides temperature control for the control room following isolation of the control room.

The CRACS consists of two trains that provide cooling of recirculated control room air. Each train consists of, cooling coils, instrumentation, and controls to provide for control room temperature control. The CRACS (CRACS 31 and CRACS 32) are powered from safeguards power trains 5A (EDG 33) and 6A (EDG 32), respectively. The CRACS units are supplied with cooling water from the essential service water header and each unit is capable of performing its design function during an accident with a service water inlet temperature ≤ 95°F.

The CRACS is an emergency system, parts of which may also operate during normal unit operations. Each CRACS unit is sized to provide 60% of the cooling capacity required during normal operation and 100% of the cooling capacity required during an accident. The CRACS operation in maintaining the control room temperature is discussed in the FSAR, Section 9.9 (Ref. 1).

During normal operation, five supplemental air-conditioning units in the Control Room are available to supplement the cooling capacity of the CRACS. These units also provide Control Room heating. These five supplemental air-conditioning units are not assumed to be available during a blackout or design basis accident and, therefore, are not governed by Technical Specifications.

APPLICABLE SAFETY ANALYSES

The design basis of the CRACS is to maintain the control room temperature for 30 days of continuous occupancy.

The CRACS components are arranged in redundant, safety related trains. The CRACS is designed so that the functional capability

BASES

APPLICABLE SAFETY ANALYSES (continued)

of the Control Room is maintained at all times, including a Design Basis Accident. Functional capability of the Control Room means that the ambient temperature for safety equipment located in this room will not exceed 108.2°F. Control Room safety equipment is specified to a temperature of 120°F and the 108.2°F limit for Control room temperature is sufficient to account for the temperature rise in the enclosed cabinets. Functional capability of the Control Room can be maintained by one train of CRACS being cooled by the essential service water system assuming the ultimate heat sink temperature is ≤ 95°F. Analysis indicates that under worst case conditions, the Control Room temperature could rise to approximately 106°F following the loss of one CRACS train assuming all lights, except emergency lights, are turned off (Ref.1). Detectors and controls are provided for control room temperature control. The CRACS is designed in accordance with Seismic Category I requirements. The CRACS is capable of removing sensible and latent heat loads from the control room, which include consideration of equipment heat loads and personnel occupancy requirements, to ensure equipment OPERABILITY.

A failure of a component of the CRACS, assuming a loss of offsite power, does not impair the ability of the system to perform its design function. However, the original CRACS design was not required to meet single failure criteria and, although upgraded from the original design, CRACS does not satisfy all requirements in IEEE-279 for single failure tolerance.

The CRACS satisfies Criterion 3 of 10 CFR 50.36.

LCO

Two trains of the CRACS are required to be OPERABLE to ensure that at least one is available, assuming a single failure disabling the other train. Total system failure could result in the equipment operating temperature exceeding limits in the event of an accident.

The CRACS is considered to be OPERABLE when the individual components necessary to maintain the control room temperature are OPERABLE in both trains. These components include the cooling

BASES

LCO (continued)

coils and common temperature control instrumentation. In addition, the CRACS must be operable to the extent that air circulation can be maintained.

Note that the required recirculation rates are demonstrated with surveillance tests conducted with the air conditioning system (CRACS) operating. An inoperable CRACS fan will affect the flow balance of the CRVS due to interconnected ductwork. Therefore, if the fan associated with one of the air-conditioning units governed by LCO 3.7.12 is inoperable, Conditions in both LCO 3.7.11, Control Room Ventilation System, and LCO 3.7.12, Control Room Air conditioning System (CRACS), will apply.

APPLICABILITY

In MODES 1, 2, 3 and 4, the CRACS must be OPERABLE to ensure that the control room temperature will not exceed equipment operational requirements following isolation of the control room.

The CRACS is not required in MODE 5 or 6, or during movement of irradiated fuel assemblies and core alterations because analysis indicates that isolation of the control room is not required for maintaining radiation exposure within acceptable limits following a fuel handling accident or gas decay tank rupture.

ACTIONS

A.1

With one CRACS train inoperable, action must be taken to restore OPERABLE status within 30 days. In this Condition, the remaining OPERABLE CRACS train is adequate to maintain the control room temperature within limits. However, the overall reliability is reduced because a single failure in the OPERABLE CRACS train could result in loss of CRACS function. The 30 day Completion Time is based on the low probability of an event requiring control room isolation, the consideration that the remaining train can provide the required protection, and that alternate nonsafety related cooling means are typically available.

BASES

ACTIONS (continued)

B.1

When neither CRACS train is Operable, action must be taken to restore at least one train to OPERABLE status within 72 hours. The 72 hour Completion Time is acceptable because of the low probability of a DBA occurring during this time period and because alternate nonsafety cooling means are typically available.

C.1 and C.2

If Required Actions A.1 or B.1 are not met within the required Completion Time, the unit must be placed in a MODE that minimizes the risk. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.12.1

This SR verifies that the heat removal capability of the system is sufficient to remove the heat load assumed in the control room. This SR consists of a combination of testing and calculations. The 24 month Frequency is appropriate since significant degradation of the CRACS is slow and is not expected over this time period.

REFERENCES

1. FSAR, Section 9.9.

B 3.7 PLANT SYSTEMS

B 3.7.13 Fuel Storage Building Emergency Ventilation System (FSBEVS)

BASES

BACKGROUND

The FSBEVS filters airborne radioactive particulates from the area of the fuel pool following a fuel handling accident. The FSBEVS, in conjunction with other normally operating systems, also provides environmental control of temperature and humidity in the fuel storage building.

The Fuel Storage Building (FSB) ventilation system maintains environmental conditions in the building enclosing the spent fuel pit and consists of the following:

Two FSB air tempering units with associated ventilation supply fans and ventilation supply isolation dampers;

One FSB exhaust fan and associated outlet damper;

One FSB exhaust filtration unit consisting of roughing, HEPA, and charcoal filters which includes the pneumatically operated inlet and outlet dampers for the carbon filter and manually operated dampers that allow the carbon filter to be bypassed;

Inflatable seals on man doors and truck door,

Area Radiation Monitor (R-5) consisting of an extended range area monitor used to measure the area radiation fields of the Fuel Storage Building; and,

Ductwork, dampers, and instrumentation needed to support system operation,

<u>During normal operation</u>, the FSB air tempering units and associated ventilation supply fans and the FSB exhaust fan operate, as necessary, to ventilate and, if necessary, heat the FSB. One or both FSB air tempering units are used to supply outside air to the south end of the FSB and the FSB exhaust fan is used to exhaust air from the north end of the FSB through the roughing filters and HEPA filters and is released to the

BACKGROUND (Continued)

environment via the plant vent. FSB air flow is directed from radiologically clean to less clean areas to prevent the spread of contamination. Additionally, the FSBEVS is designed so that the exhaust fan capacity is greater than the supply fan(s) capacity so that the FSB is normally maintained at a slight negative pressure. This ensures that ventilation air leaving the FSB passes through the filters and HEPA in the exhaust filtration unit and is released to the environment via the plant vent. When not handing irradiated fuel in the FSB, the carbon filter in the exhaust filtration unit is normally bypassed to extend the life of the charcoal. In this configuration, the manually operated charcoal filter bypass dampers are left open and the automatically operated charcoal filter face dampers (inlet and outlet dampers) are closed.

<u>During irradiated fuel handling activities in the FSB,</u> the FSBEVS is operated as described above except that the manually operated charcoal filter bypass dampers are closed and the charcoal filter face dampers (inlet and outlet dampers) are opened. In this configuration, the FSB is still maintained at a slight negative pressure but all FSB ventilation exhaust is directed through the roughing filters, HEPA filters, and charcoal filters and is released to the environment via the plant vent.

<u>Following an Area Radiation Monitor (R-5) signal or manual actuation to the emergency mode of operation</u>, the ventilation supply fans stop automatically and the associated ventilation supply dampers close automatically. The charcoal filter face dampers (inlet and outlet dampers) open automatically, if not already open. Additionally, the rolling truck door closes, if open, and the inflatable seals on the man doors and truck door are actuated. The FSB exhaust fan continues to operate. With the FSB ventilation supply stopped and the FSB boundary secured, the FSB exhaust fan is capable of maintaining the FSB at a pressure ≤ -0.5 inches water gauge with respect to atmospheric pressure with the exhaust flow rate ≤ 20,000 cfm. Ventilation dampers required to establish the boundary or flow path (e.g., air tempering unit ventilation supply inlet dampers) will fail-safe into the required emergency mode position. Note that the

BASES

BACKGROUND (Continued)

inflatable seals on man doors and truck door are not required for maintaining the FSB at these required post accident conditions.

A push button switch adjacent to the 95' elevation door leading to the Fan House allows the Fuel Storage Building Exhaust Fan to be momentarily shut down and air removed from the man door seal to allow the door to be opened for FSB ingress or egress when in the emergency mode of operation. The fan will automatically restart and the door is resealed after a preset time has elapsed (approximately 30 seconds).

The FSBEVS is discussed in the FSAR, Sections 9.5, and 14.2 (Refs. 1 and 2, respectively).

APPLICABLE SAFETY ANALYSES

The FSBEVCS design basis is established by the consequences of the limiting Design Basis Accident (DBA), which is a fuel handling accident. The analysis for a fuel handling accident assumes that the FSB exhaust fan can maintain the FSB at a slight negative pressure (i.e., ≤ -0.125 inches water gauge) with respect to atmospheric pressure with the exhaust flow rate ≤ 20,000 cfm. Under these conditions, all FSB ventilation exhaust is assumed to be directed through the roughing filters, HEPA filters, and charcoal filters and is released to the environment via the plant vent. This ensures that offsite post accident dose rates are within required limits. Although this LCO requires the OPERABILITY of the FSBEVS whenever irradiated fuel assemblies are being moved within the FSB, analysis indicates that offsite post accident dose rates will be within required limits without the operation of the FSBEVS if the irradiated fuel has had a continuous 45 day decay period. This analysis is described in Reference 2.

The FSBEVS satisfies Criterion 3 of 10 CFR 50.36.

BASES

LCO

This LCO requires that the Fuel Storage Building Emergency Ventilation System is OPERABLE and the FSB boundary is intact. This ensures that the required negative pressure is maintained in the FSB and FSB ventilation exhaust is directed through the roughing filters, HEPA filters, and charcoal filters and is released to the environment via the plant vent. Failure of the FSBEVS or the FSB boundary could result in the atmospheric release from the fuel storage building exceeding the 10 CFR 100 (Ref. 3) limits in the event of a fuel handling accident.

The FSBEVS is considered OPERABLE when the individual components necessary to control exposure in the fuel storage building are OPERABLE. FSBEVS is considered OPERABLE when its associated:

a. Exhaust fan is OPERABLE;

b. Roughing filter, HEPA filter and charcoal adsorber are not excessively restricting flow, and are capable of performing their filtration function;

c. Ductwork and dampers are OPERABLE as needed to ensure air circulation can be maintained through the filter; and

d. Ventilation supply fan trip function and ventilation supply isolation dampers closure function are OPERABLE or secured in incident position; and

e. FSBEVS charcoal filter bypass dampers are closed and leak tested.

The inflatable seals on man doors and truck door are not required for maintaining the FSB at these required post accident conditions. Additionally, the FSBEVS is not rendered inoperable when the FSBEVS exhaust fan is momentarily shut down and air removed from the door seal to allow the door to be opened for FSB ingress or egress when in the emergency mode of operation.

Requirements for the OPERABILITY of the Area Radiation Monitor (R-5) and associated instrumentation that initiates the FSBEVS are addressed in LCO 3.3.8, "Fuel Storage Building Emergency Ventilation System Actuation Instrumentation."

BASES

LCO (continued)

Requirements for leak testing the FSBEVS charcoal filter bypass dampers following closure are governed by the IP3 FSAR.

APPLICABILITY

During movement of irradiated fuel in the fuel storage building, the FSBEVS is required to be OPERABLE to mitigate the consequences of a fuel handling accident.

ACTIONS

A.1

When the FSBEVS is inoperable during movement of irradiated fuel assemblies in the fuel storage building, action must be taken to place the unit in a condition in which the LCO does not apply. Action must be taken immediately to suspend movement of irradiated fuel assemblies in the fuel storage building. This does not preclude the movement of fuel to a safe position.

SURVEILLANCE REQUIREMENTS

SR 3.7.13.1

This SR requires periodic verification that the FSBEVS charcoal filter bypass dampers are installed and leak tested. This SR is performed by a visual verification that the bypass dampers are installed and an administrative verification that required leak testing was performed following the last installation of the dampers. Requirements for leak testing the FSBEVS charcoal filter bypass dampers following closure are governed by the IP3 FSAR.

This SR is performed prior to movement of irradiated fuel assemblies in the fuel storage building, and once per 92 days thereafter. The 92 day Frequency is appropriate because the bypass dampers are operated under administrative controls which provides a high degree of assurance that the dampers will remain

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.13.1 (continued)

in the required position. This Frequency has been shown to be acceptable through operating experience.

SR 3.7.13.2

Standby systems should be checked periodically to ensure that they function properly. As the environmental and normal operating conditions on this system are not severe, testing the FSBEVS once every 31 days provides an adequate check on this system. Systems are operated for ≥ 15 minutes to demonstrate the function of the system. The 31 day Frequency is based on the known reliability of the equipment.

SR 3.7.13.3

This SR verifies that the required FSBEVS testing is performed in accordance with the Ventilation Filter Testing Program (VFTP). The FSBEVS filter tests are in accordance with the applicable portions of Regulatory Guide 1.52 (Ref. 4) as specified in the VFTP. The VFTP includes testing HEPA filter performance, charcoal adsorber efficiency, minimum system flow rate, and the physical properties of the activated charcoal (general use and following specific operations). Specific test frequencies and additional information are discussed in detail in the VFTP.

SR 3.7.13.4

This SR verifies that the FSBEVS starts and operates on an actual or simulated actuation signal. The 92 day Frequency ensures that the SR is performed within a short time prior to a potential need for the FSBEVS and allows the SR to be performed only once prior to or during a refueling outage. This SR Frequency is based on the demonstrated reliability of the system.

SR 3.7.13.5

This SR verifies the integrity of the fuel storage building enclosure. The ability of the fuel building to maintain negative

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.13.5 (continued)

pressure with respect to potentially uncontaminated adjacent areas is periodically tested to verify proper function of the FSBEVS. During the normal mode of operation, the FSBEVS is designed to maintain a slight negative pressure in the fuel storage building, to prevent unfiltered LEAKAGE. This test verifies that the FSB exhaust fan can maintain the FSB at a slight negative pressure (i.e., ≤ -0.125 inches water gauge) with respect to atmospheric pressure with the exhaust flow rate ≤ 20,000 cfm during a fuel handling accident. The Frequency of 24 months is consistent with the guidance provided in NUREG-0800, Section 6.5.1 (Ref. 5).

REFERENCES

1. FSAR, Section 9.5.
2. FSAR, Section 14.2.
3. 10 CFR 100.
4. Regulatory Guide 1.52 (Rev. 2).
5. NUREG-0800, Section 6.5.1, Rev. 2, July 1981.

B 3.7 PLANT SYSTEMS

B 3.7.14 Spent Fuel Pit Water Level

BASES

BACKGROUND

The minimum water level in the spent fuel pit meets the assumptions of iodine decontamination factors following a fuel handling accident. The specified water level shields and minimizes the general area dose when the storage racks are filled to their maximum capacity. The water also provides shielding during the movement of spent fuel.

A general description of the spent fuel pit design and the Spent Fuel Cooling and Cleanup System is given in the FSAR, Section 9.5 (Ref. 1). The assumptions of the fuel handling accident are given in the FSAR, Section 14.2 (Ref. 2).

APPLICABLE SAFETY ANALYSES

The minimum water level in the spent fuel pit meets the assumptions of the fuel handling accident described in FSAR, Section 14.2 (Ref. 2). The resultant 2 hour thyroid dose per person at the exclusion area boundary is a small fraction of the 10 CFR 100 (Ref. 3) limits.

According to Reference 2, there is 23 ft of water between the top of the damaged fuel bundle and the fuel pool surface during a fuel handling accident. With 23 ft of water, the assumptions of Reference 2 can be used directly. In practice, this LCO preserves this assumption for the bulk of the fuel in the storage racks.

The Spent Fuel Pit water level satisfies Criteria 2 and 3 of 10 CFR 50.36.

LCO

The spent fuel pit water level is required to be ≥ 23 ft over the top of irradiated fuel assemblies seated in the storage racks. The specified water level preserves the assumptions of the fuel

BASES

LCO (continued)

handling accident analysis (Ref. 2). As such, it is the minimum required for fuel storage and movement within the spent fuel pit.

APPLICABILITY

This LCO applies during movement of irradiated fuel assemblies in the spent fuel pit, since the potential for a release of fission products exists.

ACTIONS

A.1

Required Action A.1 is modified by a Note indicating that LCO 3.0.3 does not apply.

When the initial conditions for prevention of an accident cannot be met, steps should be taken to preclude the accident from occurring. When the spent fuel pit water level is lower than the required level, the movement of irradiated fuel assemblies in the spent fuel pit is immediately suspended to a safe position. This action effectively precludes the occurrence of a fuel handling accident. This does not preclude movement of a fuel assembly to a safe position.

If moving irradiated fuel assemblies while in MODE 5 or 6, LCO 3.0.3 would not specify any action. If moving irradiated fuel assemblies while in MODES 1, 2, 3, and 4, the fuel movement is independent of reactor operations. Therefore, inability to suspend movement of irradiated fuel assemblies is not sufficient reason to require a reactor shutdown.

SURVEILLANCE REQUIREMENTS

SR 3.7.14.1

This SR verifies sufficient spent fuel pit water is available in the event of a fuel handling accident. The water level in the

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.14.1 (continued)

spent fuel pit must be checked periodically. The 7 day Frequency is appropriate because the volume in the spent fuel pit is normally stable. Water level changes are controlled by plant procedures and are acceptable based on operating experience.

During refueling operations, the level in the spent fuel pit is normally in equilibrium with the refueling canal and reactor cavity, and the level in the refueling reactor cavity is checked daily in accordance with SR 3.9.6.1.

REFERENCES

1. FSAR, Section 9.5.
2. FSAR, Section 14.2.
3. 10 CFR 100.11.

B 3.7 PLANT SYSTEMS

B 3.7.15 Spent Fuel Pit Boron Concentration

BASES

BACKGROUND

In the Maximum Density Rack (MDR) design, the spent fuel storage pool is divided into two separate and distinct regions. The layout of the IP3 MDR is shown in Figure B 3.7.16-1. As shown in Figure B 3.7.16-1, Region 1 (Columns SS-ZZ, Rows 35-64) includes 240 storage positions and Region 2 (Columns A-RR, Rows 1-34) includes 1105 storage positions. Region 1 is analyzed for storage of high-enrichment and low-burnup fuel. Region 2 is analyzed for storage of fuel with either higher burnup or lower enrichment. Each region has been separately analyzed for close packed storage when all cells in that region contain fuel of the highest reactivity stored in accordance with LCO 3.7.16, Spent Fuel Assembly Storage. This analysis is the basis for the restrictions on fuel storage locations established by LCO 3.7.16.

Limits, based on a combination of initial enrichment and burnup, are used to determine if a fuel assembly must be stored in region 1 or if the fuel assembly may be stored in either region 1 or region 2. Fuel with the highest initial enrichments are subject to additional restrictions even when stored in region 1. Fuel assemblies with an initial enrichment > 5.0 wt% U-235 cannot be stored in the spent fuel pit in accordance with paragraph 4.3.1.1 in Section 4.3, Fuel Storage.

The water in the spent fuel pit normally contains soluble boron, which results in large subcriticality margins under actual operating conditions. However, the NRC guidelines, based upon the accident condition in which all soluble poison is assumed to have been lost, specify that the limiting k_{eff} of 0.95 be evaluated in the absence of soluble boron. Hence, the design of both regions is based on the use of unborated water, which maintains each region in a subcritical condition during normal operation with the regions fully loaded when fuel storage locations, enrichment and burnup are in conformance with analysis assumptions as specified in LCO 3.7.16. The double contingency principle discussed in ANSI N-16.1-1975 and the April 1978 NRC letter (Ref. 1) allows credit for soluble boron under other abnormal or accident conditions, because only a single accident

BASES

BACKGROUND (Continued)

need be considered at one time. For example, the accident scenarios include movement of fuel from Region 1 to Region 2, or accidental misloading of a fuel assembly in Region 1. This event could increase the potential for criticality of the spent fuel pit. To mitigate these postulated criticality related accidents, boron concentration is verified by SR 3.7.15.1 to be within the limits specified in this LCO prior to movement of fuel assemblies in the spent fuel pit. Safe operation of the MDR with no movement of assemblies is achieved by controlling the location of each assembly in accordance with LCO 3.7.16, "Spent Fuel Assembly Storage." Prior to movement of an assembly, it is necessary to perform SR 3.7.15.1.

APPLICABLE SAFETY ANALYSES

Most accident conditions do not result in an increase in the reactivity of either of the two regions. Examples of these accident conditions are the loss of cooling (reactivity increase with decreasing water density) and the dropping of a fuel assembly on the top of the rack. However, accidents can be postulated that could increase the reactivity. This increase in reactivity is unacceptable with unborated water in the storage pool. Thus, for these accident occurrences, the presence of soluble boron in the storage pool prevents criticality in both regions. The postulated accidents are basically of two types. A fuel assembly could be incorrectly transferred from Region 1 to Region 2 (e.g., an unirradiated fuel assembly or an insufficiently depleted fuel assembly). The second type of postulated accidents is associated with a fuel assembly which is dropped adjacent to the fully loaded storage rack. This could have a small positive reactivity effect on the Region. However, the negative reactivity effect of the soluble boron compensates for the increased reactivity caused by either one of the two postulated accident scenarios. The accident analyses is described in References 2 and 3.

The concentration of dissolved boron in the spent fuel pit satisfies Criterion 2 of 10 CFR 50.36.

BASES

LCO

The spent fuel pit boron concentration is required to be ≥ 1000 ppm. The specified concentration of dissolved boron in the spent fuel pit preserves the assumptions used in the analyses of the potential critical accident scenarios as described in Reference 3. This concentration of dissolved boron is the minimum required concentration for fuel assembly storage and movement within the spent fuel pit until a spent fuel pit verification confirms that there are no mis-loaded fuel assemblies. With no mis-loaded fuel assemblies and unborated water, the spent fuel pit design is sufficient to maintain the core at $k_{eff} \leq 0.95$.

APPLICABILITY

This LCO applies whenever fuel assemblies are stored in the spent fuel pit, until a complete spent fuel pit verification has been performed on all fuel that was moved since the last verification following the last movement of fuel assemblies in the spent fuel pit. This LCO does not apply following the verification, since the verification would confirm that there are no misloaded fuel assemblies. With no further fuel assembly movements in progress, there is no potential for a misloaded fuel assembly or a dropped fuel assembly.

ACTIONS

A.1, A.2.1 and A.2.2

The Required Actions are modified by a Note indicating that LCO 3.0.3 does not apply.

When the concentration of boron in the spent fuel pit is less than required, immediate action must be taken to preclude the occurrence of an accident or to mitigate the consequences of an accident in progress. This is most efficiently achieved by immediately suspending the movement of fuel assemblies. The concentration of boron is restored simultaneously with suspending movement of fuel assemblies. Alternatively, beginning a verification of the Spent Fuel Pit fuel locations, to ensure proper locations of the fuel, can be performed. However, prior to resuming movement of fuel assemblies, the concentration of

BASES

ACTIONS

A.1, A.2.1 and A.2.2 (continued)

boron must be restored. This does not preclude movement of a fuel assembly to a safe position.

If the LCO is not met while moving irradiated fuel assemblies in MODE 5 or 6, LCO 3.0.3 would not be applicable. If moving irradiated fuel assemblies while in MODE 1, 2, 3, or 4, the fuel movement is independent of reactor operation. Therefore, inability to suspend movement of fuel assemblies is not sufficient reason to require a reactor shutdown.

SURVEILLANCE REQUIREMENTS

SR 3.7.15.1

This SR verifies that the concentration of boron in the spent fuel pit is within the required limit. As long as this SR is met, the analyzed accidents are fully addressed. The 7 day Frequency is appropriate because no major replenishment of spent fuel pit water is expected to take place over such a short period of time. This SR is not required to be met or performed if a spent fuel pit verification for conformance with LCO 3.7.16, Figures 3.7.16-1 and 3.7.16-2, has been performed on all fuel assemblies moved since the last verification.

REFERENCES

1. Double contingency principle of ANSI N16.1-1975, as specified in the April 14, 1978 NRC letter (Section 1.2) and implied in the proposed revision to Regulatory Guide 1.13 (Section 1.4, Appendix A).

2. SER related to Amendment 173 to Facility Operating License No. DPR-64, Indian Point Nuclear Generating Unit No. 3, April 15, 1997.

BASES

REFERENCES (continued)

3. Criticality Analysis of the Indian Point 3 Fresh and Spent Fuel Racks, Westinghouse Commercial Nuclear Fuel Division, October, 1996.

B 3.7 PLANT SYSTEMS

B 3.7.16 Spent Fuel Assembly Storage

BASES

BACKGROUND

In the Maximum Density Rack (MDR) design, the spent fuel pit (SFP) is divided into two separate and distinct regions. The layout of the IP3 MDR is shown in Figure B 3.7.16-1, IP3 Maximum Density Spent Fuel Pit Racks, Regions and Indexing. As shown in Figure B 3.7.16-1, Region 1 (i.e., Columns SS-ZZ, Rows 35-64) includes 240 storage positions and Region 2 (i.e., Columns A-RR, Rows 1-34) includes 1105 storage positions. Region 1 is analyzed for storage of high-enrichment and low-burnup fuel. Region 2 is analyzed for storage of fuel with either higher burnup or lower enrichment. Each region has been separately analyzed for close packed storage when all cells in that region contain fuel of the highest reactivity that is allowed by this LCO. This analysis is the basis for the restrictions on fuel storage locations established by this LCO.

Prior to storage in the spent fuel pit, fuel assemblies are classified as to the level of reactivity based on the initial enrichment and burnup. This classification is made using Figure 3.7.16-1, "Fuel Assembly Classification for Storage in the Spent Fuel Pit". This classification is used to determine in which region a particular fuel assembly may be stored and if additional restrictions must be applied to the assemblies in adjacent locations. Figure 3.7.16-1, "Fuel Assembly Classification for Storage in the Spent Fuel Pit", is used to classify each assembly into one of the following categories based on initial U-235 enrichment and burnup:

Type 2 assemblies are the least reactive assemblies and include any assembly for which the combination of initial enrichment and burnup places the assembly in the domain labeled Type 2 in Figure 3.7.16-1. Type 2 assemblies may be stored in any location in Region 1 or Region 2 of Figure B 3.7.16-1.

Type 1A assemblies are more reactive than Type 2 assemblies and include any assembly for which the combination of initial enrichment and burnup places the assembly in the domain labeled Type 1A in Figure 3.7.16-1. Type 1A assemblies must be stored in

BASES

BACKGROUND (Continued)

Region 1 of Figure B 3.7.16-1 but may be stored in any location in Region 1.

Type 1B assemblies are more reactive than Type 1A assemblies and include any assembly with an initial enrichment > 4.2 but ≤ 4.6 wt% U-235 with a burnup that places the assembly in the domain labeled Type 1B in Figure 3.7.16-1. Type 1B assemblies must be stored in Region 1 of Figure B 3.7.16-1 but may be stored in any location in Region 1 except in locations that are face-adjacent to a Type 1C assembly.

Type 1C assemblies are the most reactive bundles permitted in accordance with Specification 4.3, Fuel Storage. Type 1C assemblies include any assembly with an initial enrichment > 4.6 but ≤ 5.0 wt% U-235 with a burnup that places the assembly in the domain labeled Type 1C on Figure 3.7.16-1. Type 1C assemblies must be stored in Region 1 of Figure B 3.7.16-1. Type 1C assemblies cannot be stored in Row 64 or in Column ZZ. Additionally, Type 1C assemblies must be stored in a location where all face-adjacent locations are as follows: a) occupied by Type 2 or Type 1A assemblies; b) occupied non-fuel components; or, c) empty.

Fuel assemblies with an initial enrichment > 5.0 wt% U-235 are not shown on Figure 3.7.16-1 and cannot be stored in the spent fuel pit in accordance with paragraph 4.3.1.1 in Section 4.3, Fuel Storage.

The water in the spent fuel pit normally contains soluble boron, which results in large subcriticality margins under actual operating conditions. However, the NRC guidelines, based upon the accident condition in which all soluble poison is assumed to have been lost, specify that the limiting k_{eff} of 0.95 be evaluated in the absence of soluble boron. Hence, the design of both regions is based on the use of unborated water, which maintains each region in a subcritical condition during normal operation with the regions fully loaded and fuel storage locations, enrichment and burnup are in conformance with analysis assumptions and this LCO. The double contingency principle

BASES

BACKGROUND (Continued)

discussed in ANSI N-16.1-1975 and the April 1978 NRC letter (Ref. 1) allows credit for soluble boron under other abnormal or accident conditions because only a single accident need be considered at one time. For example, the accident scenarios include movement of a type 1C fuel assembly from Region 1 to Region 2, or accidental misloading of a fuel assembly in Region 1. These events could increase the potential for criticality in the Spent Fuel Pit. To mitigate these postulated criticality related accidents, boron concentration is verified to be within the limits specified in LCO 3.7.15, Spent Fuel Pit Boron Concentration, prior to movement of any fuel assembly. Safe operation of the SFP with no movement of assemblies is achieved by controlling the location of each assembly in accordance with the accompanying LCO. However, prior to movement of an assembly, it is necessary to perform SR 3.7.15.1 (i.e., verification that the spent fuel pit boron concentration is within limit).

APPLICABLE SAFETY ANALYSES

The restrictions on the placement of fuel assemblies within the spent fuel pit are based on initial enrichment and burnup which is indicative of fuel assembly reactivity. Storage locations are then restricted to ensure the k_{eff} of the spent fuel pit will always remain < 0.95, assuming the pool to be flooded with unborated water. Fuel assemblies not meeting the criteria of Figure 3.7.16-1 may not be stored in accordance with Specification 4.3.1.1 in Section 4.3.

The hypothetical accidents can only take place during or as a result of the movement of an assembly (References 2 and 3). For these accident occurrences, the presence of soluble boron in the spent fuel storage pit (controlled by LCO 3.7.15, "Spent Fuel Pit Boron Concentration") prevents criticality in both regions. By closely controlling the movement of each assembly and by checking the location of each assembly after movement, the time period for potential accidents may be limited to a small fraction of the total operating time. During the remaining time period

BASES

APPLICABLE SAFETY ANALYSES (continued)

with no potential for accidents, the operation may be under the auspices of the accompanying LCO.

The configuration of fuel assemblies in the fuel storage pit satisfies Criterion 2 of 10 CFR 50.36.

LCO

Fuel assemblies stored in the spent fuel pit are classified in accordance with Figure 3.7.16-1 based on initial enrichment and burnup which is indicative of fuel assembly reactivity. Based on this classification, fuel assembly storage location within the spent fuel pit and storage location relative to other assemblies is restricted in accordance with the rules established by this LCO.

Fuel assemblies with an initial enrichment > 5.0 wt% U-235 are not shown on Figure 3.7.16-1 because fuel assemblies with this enrichment cannot be stored in the spent fuel pit in accordance with limits established in Technical Specification Section 4.3.

APPLICABILITY

This LCO applies whenever any fuel assembly is stored in the spent fuel pit.

ACTIONS

A.1

Required Action A.1 is modified by a Note indicating that LCO 3.0.3 does not apply.

When the configuration of fuel assemblies stored in the spent fuel pit is not in accordance with this LCO, the immediate action is to initiate action to make the necessary fuel assembly movement(s) to bring the configuration into compliance with this LCO.

If unable to move irradiated fuel assemblies while in MODE 5 or 6, LCO 3.0.3 would not be applicable. If unable to move irradiated fuel assemblies while in MODE 1, 2, 3, or 4, the

BASES

ACTIONS

A.1 (continued)

action is independent of reactor operation. Therefore, inability to move fuel assemblies is not sufficient reason to require a reactor shutdown.

SURVEILLANCE REQUIREMENTS

SR 3.7.16.1

This SR verifies by administrative means that the initial enrichment and burnup of the fuel assembly in each location is in accordance with the accompanying LCO.

REFERENCES

1. Double contingency principle of ANSI N16.1-1975, as specified in the April 14, 1978 NRC letter (Section 1.2) and implied in the proposed revision to Regulatory Guide 1.13 (Section 1.4, Appendix A).

2. SER related to Amendment 173 to Facility Operating License No. DPR-64, Indian Point Nuclear Generating Unit No. 3, April 15, 1997.

3. Criticality Analysis of the Indian Point 3 Fresh and Spent Fuel Racks, Westinghouse Commercial Nuclear Fuel Division, October, 1996.

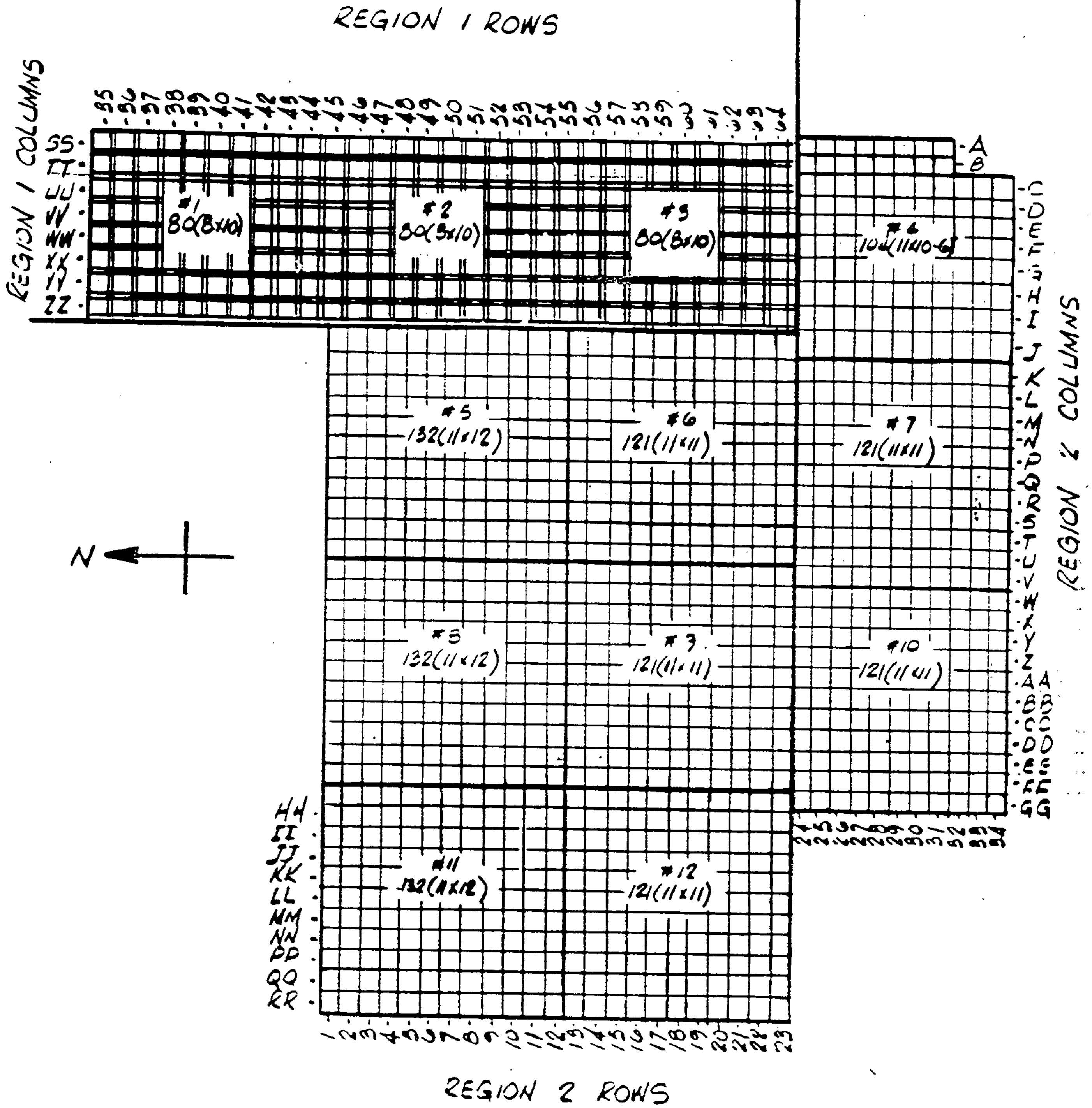

Figure B 3.7.16-1 (Page 1 of 1)
Maximum Density Spent Fuel Pit (SFP)
Racks, Regions and Indexing

B 3.7 PLANT SYSTEMS

B 3.7.17 Secondary Specific Activity

BASES

BACKGROUND

Activity in the secondary coolant results from steam generator tube outleakage from the Reactor Coolant System (RCS). Under steady state conditions, the activity is primarily iodines with relatively short half lives and, thus, indicates current conditions. During transients, I-131 spikes have been observed as well as increased releases of some noble gases. Other fission product isotopes, as well as activated corrosion products in lesser amounts, may also be found in the secondary coolant.

A limit on secondary coolant specific activity during power operation minimizes releases to the environment because of normal operation, anticipated operational occurrences, and accidents.

This limit is lower than the activity value that might be expected from a 1 gpm tube leak (LCO 3.4.13, "RCS Operational LEAKAGE") of primary coolant at the limit of 1.0 μCi/gm (LCO 3.4.16, "RCS Specific Activity"). The steam line failure is assumed to result in the release of the noble gas and iodine activity contained in the steam generator inventory, the feedwater, and the reactor coolant LEAKAGE. Most of the iodine isotopes have short half lives, (i.e., < 20 hours).

Operating a unit at the allowable limits could result in a 2 hour exclusion area boundary (EAB) or site boundary exposure of a small fraction (i.e., 10%) of the 10 CFR 100 (Ref. 1) limits (i.e., 25 rem whole body and 300 rem thyroid), or the limits established as the NRC staff approved licensing basis.

APPLICABLE SAFETY ANALYSES

The accident analysis of the main steam line break (MSLB), as discussed in the FSAR, Chapter 14.2 (Ref. 2) assumes the initial secondary coolant specific activity to have a radioactive isotope concentration of 0.10 μCi/gm DOSE EQUIVALENT I-131. This assumption is used in the analysis for determining the

BASES

APPLICABLE SAFETY ANALYSES (continued)

radiological consequences of the postulated accident. The accident analysis, based on this and other assumptions, shows that the radiological consequences of an MSLB do not exceed a small fraction of the EAB (i.e., site boundary) limits (Ref. 1) for whole body and thyroid dose rates.

With the loss of offsite power, the remaining steam generators are available for core decay heat dissipation by venting steam to the atmosphere through the MSSVs and steam generator atmospheric dump valves (ADVs). The Auxiliary Feedwater System supplies the necessary makeup to the steam generators. Venting continues until the reactor coolant temperature and pressure have decreased sufficiently for the Residual Heat Removal System to complete the cooldown.

In the evaluation of the radiological consequences of this accident, the activity released from the steam generator connected to the failed steam line is assumed to be released directly to the environment. The unaffected steam generator is assumed to discharge steam and any entrained activity through the MSSVs and ADVs during the event. Credit is taken in the analysis for activity plateout or retention; however, the resultant radiological consequences represent a conservative estimate of the potential integrated dose due to the postulated steam line failure.

Secondary specific activity limits satisfy Criterion 2 of 10 CFR 50.36.

LCO

As indicated in the Applicable Safety Analyses, the specific activity of the secondary coolant is required to be $\leq 0.10\ \mu$Ci/gm DOSE EQUIVALENT I-131 to limit the radiological consequences of a Design Basis Accident (DBA) to a small fraction of the required limit (Ref. 1).

Monitoring the specific activity of the secondary coolant ensures that when secondary specific activity limits are exceeded, appropriate actions are taken in a timely manner to place the

BASES

LCO (continued)

unit in an operational MODE that would minimize the radiological consequences of a DBA.

APPLICABILITY

In MODES 1, 2, 3, and 4, the limits on secondary specific activity apply due to the potential for secondary steam releases to the atmosphere.

In MODES 5 and 6, the steam generators are not normally used for heat removal. Both the RCS and steam generators are depressurized, and primary to secondary LEAKAGE is minimal. Therefore, monitoring of secondary specific activity is not required.

ACTIONS

A.1 and A.2

DOSE EQUIVALENT I-131 exceeding the allowable value in the secondary coolant, is an indication of a problem in the RCS and contributes to increased post accident doses. If the secondary specific activity cannot be restored to within limits within the associated Completion Time, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 6 hours, and in MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.17.1

This SR verifies that the secondary specific activity is within the limits of the accident analysis. A gamma isotopic analysis of the secondary coolant, which determines DOSE EQUIVALENT I-131,

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.17.1 (continued)

confirms the validity of the safety analysis assumptions as to the source terms in post accident releases. It also serves to identify and trend any unusual isotopic concentrations that might indicate changes in reactor coolant activity or LEAKAGE. The 31 day Frequency is based on the detection of increasing trends of the level of DOSE EQUIVALENT I-131, and allows for appropriate action to be taken to maintain levels below the LCO limit.

REFERENCES

1. 10 CFR 100.11.

2. FSAR, Chapter 14.2.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.1 AC Sources – Operating

BASES

BACKGROUND

The unit Electrical Power Distribution System AC sources consist of the following: two offsite circuits (the normal or 138 kV circuit and the alternate or 13.8 kV circuit), each of which has a preferred and backup feeder; and, the onsite standby power circuit consisting of three diesel generators. As required by 10 CFR 50, Appendix A, GDC 17 (Ref. 1), the design of the AC electrical power system provides independence and redundancy to ensure an available source of power to the Engineered Safety Feature (ESF) systems.

The onsite plant distribution system is configured around 6.9 kV buses Nos. 1, 2, 3, 4, 5, and 6. All offsite power to safeguards buses enter the plant via 6.9 kV buses Nos.5 and 6 which are connected to the 138 kV (normal) offsite circuit and have the ability to be connected to the 13.8 kV (alternate) offsite circuit. 6.9 kV buses 1, 2, 3, and 4, which supply power to the 4 reactor coolant pumps (RCPs), typically receive power from the main generator via the unit auxiliary transformer (UAT) when the plant is at power. However, when the main generator or UAT is not capable of supporting this arrangement, 6.9 kV buses 1 and 2 receive offsite power via 6.9 kV bus 5 and 6.9 kV buses 3 and 4 receive offsite power via 6.9 kV bus 6. Following a unit trip, 6.9 kV buses 1, 2, 3, and 4 will auto transfer (fast transfer) to 6.9 kV buses 5 and 6 in order to receive offsite power. The 6.9 kV buses supply power to the 480 V buses using 6.9 kV/480 V station service transformers (SSTs) as follows: 6.9 kV bus 5 supplies 480 V bus 5A via SST 5; 6.9 kV bus 6 supplies 480 V bus 6A via SST 6; 6.9 kV bus 2 supplies 480 V bus 2A via SST 2; and, 6.9 kV bus 3 supplies 480 V bus 3A via SST 3.

The onsite AC Power Distribution System begins with 480 V buses 5A, 6A, 2A and 3A and is divided into 3 safeguards power trains (trains) consisting of the 480 volt safeguards bus(es) and associated AC electrical power distribution subsystems, 125 volt DC bus subsystems, and 120 volt vital AC instrument bus subsystems. The three trains are designed such that any two trains are capable of meeting minimum requirements for accident

BASES

BACKGROUND (Continued)

mitigation and/or safe shutdown. The three safeguards power trains are train 5A (480 volt bus 5A and associated DG 33), train 6A (480 volt bus 6A and associated DG 32), and train 2A/3A (480 volt buses 2A and 3A and associated DG 31).

Offsite power is supplied to the plant from the transmission network by two electrically and physically separated circuits, the 138 kV or normal circuit and the 13.8 kV or alternate circuit. Each of the offsite circuits from the Buchanan substation into the plant is required to be supported by a physically independent circuit from the offsite network into the Buchanan substation. All offsite power enters the plant via 6.9 kV buses Nos.5 and 6 which are connected to the 138 kV (normal) offsite circuit and have the ability to be connected to the 13.8 kV (alternate) offsite circuit. This arrangement satisfies the requirement that at least one of the two required circuits can within a few seconds, provide power to safety-related equipment following a loss-of-coolant accident. Operator action is required to supply offsite power to the plant using the 13.8 kV (alternate) offsite source.

The 138 kV circuit and the 13.8 kV circuit each have a preferred and a backup feeder that connects the circuit to the Buchanan substation. For both the 138 kV and 13.8 kV circuits, the preferred IP3 feeder is the backup IP2 feeder and the backup IP3 feeder is the preferred IP2 feeder.

For the 138 kV (i.e., normal) offsite circuit, IP2 and IP3 each have a dedicated Station Auxiliary Transformer (SAT) that can be supplied by either a preferred or backup feeder. The normal or 138 kV offsite circuit, including the SAT used exclusively for IP3, is designed to supply all IP3 loads, including 4 operating RCPs and ESF loads, when using either the preferred (95331) or backup (95332) feeder. There are no special restrictions when IP2 and IP3 are both using the same 138 kV feeder concurrently.

For the 13.8 kV (i.e., alternate) offsite circuit, there is a 13.8 kV/6.9 kV auto-transformer associated with feeder 13W92 and a 13.8 kV/6.9 kV auto-transformer associated with feeder 13W93. Feeder 13W93 and its associated auto-transformer is the preferred

BASES

BACKGROUND (Continued)

feeder for the IP3 alternate (13.8 kV) circuit and the backup feeder for the IP2 alternate (13.8 kV) circuit. Feeder 13W92 and its associated auto-transformer is the backup feeder for the IP3 alternate (13.8 kV) circuit and the preferred feeder for the IP2 alternate (13.8 kV) circuit.

An offsite circuit consists of all breakers, transformers, switches, interrupting devices, cabling, and controls required to transmit power from the offsite transmission network to the onsite 480 V ESF bus(es).

The onsite standby power source consists of 3 480 V diesel generators (DGs) with a separate DG dedicated to each of the safeguards power trains. Safeguards power train 5A (480 V bus 5A) is supported by DG 33; safeguards power train 6A (480 V bus 6A) is supported by DG 32; and, safeguards power train 2A/3A (480 V buses 2A and 3A) is supported by DG 31. A DG starts automatically on a safety injection (SI) signal or on an ESF bus undervoltage signal (refer to LCO 3.3.5, "Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation"). After the DG has started, it will automatically tie to its respective bus after offsite power is tripped as a consequence of ESF bus undervoltage, independent of or coincident with an SI signal. The DGs will also start and operate in the standby mode without tying to the ESF bus on an SI signal alone. Following the trip of offsite power, an undervoltage signal strips nonpermanent loads from the ESF bus. When the DG is tied to the ESF bus, loads are then sequentially connected to its respective ESF bus by individual load timers. The sequencing logic controls the permissive and starting signals to motor breakers to prevent overloading the DG by automatic load application.

In the event of a loss of 138 kV or normal offsite source, the ESF electrical loads are automatically connected to the DGs in sufficient time to provide for safe reactor shutdown and to mitigate the consequences of a Design Basis Accident (DBA) such as a loss of coolant accident (LOCA).

Certain required unit loads are returned to service in a predetermined sequence in order to prevent overloading the DG in

BASES

BACKGROUND (Continued)

the process. Within 1 minute after the initiating signal is received, all loads needed to recover the unit or maintain it in a safe condition are returned to service.

Ratings for DGs 31, 32 and 33 are consistent with the requirements of Regulatory Guide 1.9 (Ref. 3). The 3 DGs each consist of an Alco model 16-251-E engine coupled to a Westinghouse 2188 kVA, 0.8 power factor, 900 rpm, 3 phase, 60 cycle, 480 volt generator. Each DG has a 2 hr rating of 1950 kW and a continuous rating of 1750 kW. The ESF loads that are powered from the 480 V ESF buses are listed in Reference 2.

APPLICABLE SAFETY ANALYSES

The initial conditions of DBA and transient analyses in the FSAR, Chapter 6 (Ref. 4) and Chapter 14 (Ref. 5), assume ESF systems are OPERABLE. The AC electrical power sources are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System (RCS), and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; 3.4, Reactor Coolant System (RCS); and Section 3.6, Containment Systems.

The OPERABILITY of the AC electrical power sources is consistent with the initial assumptions of the Accident analyses and is based upon meeting the design basis of the unit. This results in maintaining at least 2 of the 3 safeguards power trains energized from either onsite or offsite AC sources during Accident conditions in the event of:

a. An assumed loss of all offsite power or all onsite AC power; and

b. A worst case single failure.

The AC sources satisfy Criterion 3 of 10 CFR 50.36.

BASES

LCO

Two qualified circuits between the offsite transmission network and the onsite Electrical Power System and separate and independent DGs for each train ensure availability of the required power to shut down the reactor and maintain it in a safe shutdown condition after an anticipated operational occurrence (AOO) or a postulated DBA.

There are two qualified circuits (normal and alternate) from the transmission network at the Buchanan Station to the onsite electric distribution system. Each of these circuits must be supported by a circuit from the offsite network into the Buchanan substation that is physically independent from the other circuit to the extent practical. The circuits into the Buchanan substation that satisfy these requirements are 96951, 96952 and 95891.

The 138 kV (i.e., normal) offsite circuit consists of one of the following: 138 kV feeder 95331 (preferred); or, 138 kV feeder 95332 (backup). Additionally, the 138 kV/6.9 kV station auxiliary transformer, circuit breakers ST5 and ST6 which supply 6.9 kV buses 5 and 6, and the following components which are common to the normal and alternate offsite circuits:

a. The 480 V bus 5A supply consisting of 6.9 kV bus 5, station service transformer 5, and circuit breakers SS5 and 52/5A;

b. The 480 V bus 2A supply consisting of 6.9 kV bus 5, circuit breaker UT2-ST5 (including autotransfer function), 6.9 kV bus 2, station service transformer 2, and circuit breakers SS2 and 52/2A;

c. The 480 V bus 6A supply consisting of 6.9 kV bus 6, station service transformer 6, and circuit breakers SS6 and 52/6A; and,

d. The 480 V bus 3A supply consisting of 6.9 kV bus 6, circuit breaker UT3-ST6 (including autotransfer function), 6.9 kV bus 3, station service transformer 3, and circuit breakers SS3 and 52/3A.

The 13.8 kV (i.e., alternate) offsite circuit consists of one of the following: 13.8 kV feeder 13W93 and its associated

BASES

LCO (continued)

13.8/6.9 kV autotransformer (preferred); or, 13.8 kV feeder 13W92 and its associated 13.8/6.9 kV autotransformer (backup). Circuit breakers GT35 and GT36, which supply 6.9 kV buses 5 and 6, and the following components are common to the normal and alternate offsite circuits:

a. The 480 V bus 5A supply consisting of 6.9 kV bus 5, station service transformer 5, and circuit breakers SS5 and 52/5A;

b. The 480 V bus 2A supply consisting of 6.9 kV bus 5, circuit breaker UT2-ST5 (not including autotransfer function), 6.9 kV bus 2, station service transformer 2, and circuit breakers SS2 and 52/2A;

c. The 480 V bus 6A supply consisting of 6.9 kV bus 6, station service transformer 6, and circuit breakers SS6 and 52/6A; and,

d. The 480 V bus 3A supply consisting of 6.9 kV bus 6, circuit breaker UT3-ST6 (not including autotransfer function), 6.9 kV bus 3, station service transformer 3, and circuit breakers SS3 and 52/3A.

If the alternate (13.8 kV) offsite circuit is being used to supply power to the plant and the Unit Auxiliary Transformer is supplying 6.9 kV bus 1, 2, 3 or 4, the size of the 13.8 kV/6.9 kV auto-transformers requires that the automatic transfer of 6.9 kV buses 1, 2, 3, and 4 to 6.9 kV buses 5 and 6 (i.e., the offsite circuit) be disabled because neither 13.8 kV/6.9 kV auto-transformer is capable of supplying 4 operating RCPs. This requirement is not intended to preclude supplying 6.9 kV buses 1, 2, 3, and 4 using the alternate offsite circuit via the 13.8 kV/6.9 kV auto-transformers once sufficient loads have been stripped from 6.9 kV buses 1, 2, 3, and 4 to assure that the 13.8 kV/6.9 kV auto-transformer will not be overloaded by these manual actions.

If IP3 and IP2 are both using a single 13.8 kV feeder (13W92 or 13W93), administrative controls are used to ensure that the

BASES

LCO (continued)

13.8 kV/6.9 kV auto-transformer load restrictions will not be exceeded.

Each offsite circuit must be capable of maintaining rated frequency and voltage, and accepting required loads during an accident, while connected to the ESF buses.

Three DGs must be capable of starting, accelerating to rated speed and voltage, and connecting to its respective ESF bus on detection of bus undervoltage. This will be accomplished within 10 seconds. Each DG must also be capable of accepting required loads within the assumed loading sequence intervals, and continue to operate until offsite power can be restored to the ESF buses.

Proper sequencing of loads, including tripping of nonessential loads, is a required function for DG OPERABILITY.

The AC sources in each safeguards power train must be separate and independent (to the extent possible) of the AC sources in the other train. For the DGs, separation and independence are complete.

For the offsite AC sources, separation and independence are to the extent practical. A circuit may be connected to more than one ESF bus, and not violate separation criteria. A circuit that is not connected to an ESF bus is required to have OPERABLE automatic or manual transfer capability to the ESF buses to support OPERABILITY of that circuit.

APPLICABILITY

The AC sources are required to be OPERABLE in MODES 1, 2, 3, and 4 to ensure that:

a. Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of AOOs or abnormal transients; and

BASES

APPLICABILITY (continued)

b. Adequate core cooling is provided and containment OPERABILITY and other vital functions are maintained in the event of a postulated DBA.

The AC power requirements for MODES 5 and 6 are covered in LCO 3.8.2, "AC Sources - Shutdown."

ACTIONS

A.1

To ensure a highly reliable power source remains with one offsite circuit inoperable, it is necessary to verify the OPERABILITY of the remaining required offsite circuit on a more frequent basis. Since the Required Action only specifies "perform," a failure of SR 3.8.1.1 acceptance criteria does not result in a Required Action not met. However, if a second required circuit fails SR 3.8.1.1, the second offsite circuit is inoperable, and Condition C, for two offsite circuits inoperable, is entered.

A.2

Required Action A.2, which applies only if the 13.8 kV offsite power circuit is being used to feed 6.9 kV buses 5 and 6 and the UAT is supplying 6.9 kV bus 1, 2, 3 or 4, prevents the automatic transfer of 6.9 kV buses 1, 2, 3, and 4 from the UAT to offsite power after a unit trip. Transfer of buses 1, 2, 3, and 4 from the UAT to offsite power could result in overloading the 13.8 kV/6.9 kV autotransformer. Having the auto-transfer disabled when the 13.8 kV offsite power circuit is supplying power to 6.9 kV buses 5 and 6 does not, by itself, cause either the 138 kV or 13.8 kV offsite power circuit to be inoperable. This requirement is not intended to preclude supplying 6.9 kV buses 1, 2, 3, and 4 using the alternate offsite circuit via the 13.8 kV/6.9 kV auto-transformers once sufficient loads have been stripped from 6.9 kV buses 1, 2, 3, and 4 to assure that the 13.8 kV/6.9 kV auto-transformer will not be overloaded by these manual actions. Automatic transfer of buses 1, 2, 3, and 4 can be disabled by placing 6.9 kV bus tie breaker control switches 1-5, 2-5, 3-6, and 4-6 in the "pull-out" position.

BASES

ACTIONS

A.2 (continued)

Although the auto-transfer feature is normally disabled prior to placing the 13.8 kV offsite power circuit in service, a Completion Time of 1 hour ensures that the 13.8 kV circuit meets requirements for Operability promptly when the alternate offsite circuit is configured to support the response of ESF functions.

A.3

Required Action A.3, which only applies if the train will not be powered automatically from an offsite source when the main turbine generator trips, is intended to provide assurance that an event coincident with a single failure of the associated DG will not result in a complete loss of redundant required features. Required safety features are designed with a redundant safety feature that is powered from a different safeguards power train. Therefore, if a required safety feature is supported by an inoperable offsite circuit, then the failure of the DG associated with that required safety feature will not result in the loss of a safety function because the safety function will be accomplished by the redundant safety feature that is powered from a different safeguards power train. However, if a required safety feature is supported by an inoperable offsite circuit and the redundant safety feature that is powered from a different safeguards power train is also inoperable, then the failure of the DG associated with that required safety feature will result in the loss of a safety function. Required Action A.3 ensures that appropriate compensatory measures are taken for a Condition where the loss of a DG could result in the loss of a safety function when an offsite circuit is not OPERABLE.

The turbine driven auxiliary feedwater pump is not required to be considered a redundant required feature, and, therefore, not required to be determined OPERABLE by this Required Action, because the design is such that the remaining OPERABLE motor driven auxiliary feedwater pump(s) is capable (without any reliance on the motor driven auxiliary feedwater pump powered by the emergency bus associated with the inoperable diesel generator) of providing 100% of the auxiliary feedwater flow assumed in the safety analysis.

BASES

ACTIONS

A.3 (continued)

The Completion Time for Required Action A.3 is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." In this Required Action, the Completion Time only begins on discovery that both:

a. The train will not have offsite power automatically supplying its loads following a trip of the main turbine generator; and

b. A required feature powered from another safaeguards power train is inoperable.

If at any time during the existence of Condition A (one offsite circuit inoperable) a redundant required feature subsequently becomes inoperable, this Completion Time begins to be tracked.

Discovering that offsite power is not automatically available to one train of the onsite Electrical Power Distribution System coincident with one or more inoperable required support or supported features, or both, that are associated with the other train that has offsite power, results in starting the Completion Times for the Required Action. Twenty-four hours is acceptable because it minimizes risk while allowing time for restoration before subjecting the unit to transients associated with shutdown.

The remaining OPERABLE offsite circuit and DGs are adequate to supply electrical power to the two remaining safeguards power trains of the onsite Distribution System. The 24 hour Completion Time takes into account the component OPERABILITY of the redundant counterpart to the inoperable required feature. Additionally, the 24 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

BASES

ACTIONS (continued)

A.4

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition A for a period that should not exceed 72 hours. With one offsite circuit inoperable, the reliability of the offsite system is degraded, and the potential for a loss of offsite power is increased, with attendant potential for a challenge to the unit safety systems. In this Condition, however, the remaining OPERABLE offsite circuit and DGs are adequate to supply electrical power to the onsite Distribution System.

The 72 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

B.1

To ensure a highly reliable power source remains with an inoperable DG, it is necessary to verify the availability of the offsite circuits on a more frequent basis. Since the Required Action only specifies "perform," a failure of SR 3.8.1.1 acceptance criteria does not result in a Required Action being not met. However, if a circuit fails to pass SR 3.8.1.1, it is inoperable. Upon offsite circuit inoperability, additional Conditions and Required Actions must then be entered.

B.2

Required Action B.2 is intended to provide assurance that a loss of offsite power, during the period that a DG is inoperable, does not result in a complete loss of redundant required features. Required safety features are designed with a redundant safety feature that is powered from a different safeguards power train. Therefore, if a required safety feature is supported by an inoperable DG, then the failure of the offsite circuit will not result in the loss of a safety function because the safety function will be accomplished by the redundant safety feature that is powered from a different safeguards power train (and DG).

BASES

ACTIONS

B.2 (continued)

However, if a required safety feature is supported by an inoperable DG and the redundant safety feature that is powered from a different safeguards power train is also inoperable, then a loss of offsite power will result in the loss of a safety function. Required Action B.2 ensures that appropriate compensatory measures are taken for a Condition where the loss of offsite power could result in the loss of a safety function when a DG is not OPERABLE.

The turbine driven auxiliary feedwater pump is not required to be considered a redundant required feature, and, therefore, not required to be determined OPERABLE by this Required Action, because the design is such that the remaining OPERABLE motor driven auxiliary feedwater pumps is capable (without any reliance on the motor driven auxiliary feedwater pump powered by the emergency bus associated with the inoperable diesel generator) of providing 100% of the auxiliary feedwater flow assumed in the safety analysis.

The Completion Time for Required Action B.2 is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." In this Required Action, the Completion Time only begins on discovery that both:

a. An inoperable DG exists; and

b. A required feature powered from another safeguards power train is inoperable.

If at any time during the existence of this Condition (one DG inoperable) a required feature subsequently becomes inoperable, this Completion Time would begin to be tracked.

Discovering one required DG inoperable coincident with one or more inoperable required support or supported features, or both, that are associated with either OPERABLE DG, results in starting the Completion Time for the Required Action. A COMPLETION TIME of four hours from the discovery of these events existing

BASES

ACTIONS

B.2 (continued)

concurrently is Acceptable because it minimizes risk while allowing time for restoration before subjecting the unit to transients associated with shutdown.

In this Condition, the remaining OPERABLE DGs and offsite circuits are adequate to supply electrical power to the onsite

Distribution System. Thus, on a component basis, single failure protection for the required feature's function may have been lost; however, function has not been lost. The 4 hour Completion Time takes into account the OPERABILITY of the redundant counterpart to the inoperable required feature. Additionally, the 4 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

B.3.1 and B.3.2

Required Action B.3.1 provides an allowance to avoid unnecessary testing of OPERABLE DG(s). If it can be determined that the cause of the inoperable DG does not exist on the OPERABLE DGs, SR 3.8.1.2 does not have to be performed. If the cause of inoperability exists on other DG(s), the other DG(s) would be declared inoperable upon discovery and Condition E of LCO 3.8.1 would be entered. Once the failure is repaired, the common cause failure no longer exists, and Required Action B.3.1 is satisfied. If the cause of the initial inoperable DG cannot be confirmed not to exist on the remaining DG(s), performance of SR 3.8.1.2 suffices to provide assurance of continued OPERABILITY of that DG.

In the event the inoperable DG is restored to OPERABLE status prior to completing either B.3.1 or B.3.2, the plant corrective action program will continue to evaluate the common cause possibility. This continued evaluation, however, is no longer under the 24 hour constraint imposed while in Condition B.

BASES

ACTIONS

B.3.1 and B.3.2 (continued)

According to Generic Letter 84-15 (Ref. 7), 24 hours is reasonable to confirm that the OPERABLE DGs are not affected by the same problem as the inoperable DG.

B.4

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition B for a period that should not exceed 72 hours.

In Condition B, the remaining OPERABLE DGs and offsite circuits are adequate to supply electrical power to the onsite Distribution System. The 72 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

C.1 and C.2

Required Action C.1, which applies when two offsite circuits are inoperable, is intended to provide assurance that an event with a coincident single failure will not result in a complete loss of redundant required safety functions. The Completion Time for this failure of redundant required features is reduced to 12 hours from that allowed for one train without offsite power (Required Action A.3). The rationale for the reduction to 12 hours is that Regulatory Guide 1.93 (Ref. 6) allows a Completion Time of 24 hours for two required offsite circuits inoperable, based upon the assumption that three complete safeguards power trains are OPERABLE. When a redundant required feature is not OPERABLE, this assumption is not the case, and a shorter Completion Time of 12 hours is appropriate. These features are powered from redundant AC safety trains. This includes motor driven auxiliary feedwater pumps. Single train features, such as turbine driven auxiliary pumps, are included as discussed in the Bases for Required Action A.3.

The Completion Time for Required Action C.1 is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an

BASES

ACTIONS

C.1 and C.2 (continued)

exception to the normal "time zero" for beginning the allowed outage time "clock." In this Required Action the Completion Time only begins on discovery that both:

a. All required offsite circuits are inoperable; and

b. A required feature is inoperable.

If at any time during the existence of Condition C (two offsite circuits inoperable) a required feature becomes inoperable, this Completion Time begins to be tracked.

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition C for a period that should not exceed 24 hours. This level of degradation means that the offsite electrical power system does not have the capability to effect a safe shutdown and to mitigate the effects of an accident; however, the onsite AC sources have not been degraded. This level of degradation generally corresponds to a total loss of the immediately accessible offsite power sources.

Because of the normally high availability of the offsite sources, this level of degradation may appear to be more severe than other combinations of two AC sources inoperable that involve one or more DGs inoperable. However, two factors tend to decrease the severity of this level of degradation:

a. The configuration of the redundant AC electrical power system that remains available is not susceptible to a single bus or switching failure; and

b. The time required to detect and restore an unavailable offsite power source is generally much less than that required to detect and restore an unavailable onsite AC source.

With both of the required offsite circuits inoperable, sufficient onsite AC sources are available to maintain the unit in a safe shutdown condition in the event of a DBA or transient. In fact, a simultaneous loss of offsite AC sources, a LOCA, and a worst

BASES

ACTIONS

C.1 and C.2 (continued)

case single failure were postulated as a part of the design basis in the safety analysis. Thus, the 24 hour Completion Time provides a period of time to effect restoration of one of the offsite circuits commensurate with the importance of maintaining an AC electrical power system capable of meeting its design criteria.

According to Reference 6, with the available offsite AC sources, two less than required by the LCO, operation may continue for 24 hours. If two offsite sources are restored within 24 hours, unrestricted operation may continue. If only one offsite source is restored within 24 hours, power operation continues in accordance with Condition A.

D.1 and D.2

Pursuant to LCO 3.0.6, the Distribution System ACTIONS would not be entered even if all AC sources to it were inoperable, resulting in de-energization. When the UAT is being used to supply 6.9 kV buses 1, 2, 3 Or 4 and the 13.8 kV offsite circuit is being used to supply 6.9 kV buses 5 and 6, the autotransfer function is disabled. Therefore, 480 V safeguards buses 2A and 3A (safeguards train 2A/3A) will not be automatically re-energized with offsite power following a plant trip until connected to the offsite circuit by operator action. Therefore, the Required Actions of Condition D are modified by a Note to indicate that when Condition D is entered with no offsite or DG AC source to any train, the Conditions and Required Actions for LCO 3.8.9, "Distribution Systems - Operating," must be immediately entered. This allows Condition D to provide requirements for the loss of one offsite circuit and one DG, without regard to whether a train would be de-energized during an event. LCO 3.8.9 provides the appropriate restrictions for a train that would be de-energized.

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition D for a period that should not exceed 12 hours.

BASES

ACTIONS

D.1 and D.2 (continued)

In Condition D, individual redundancy is lost in both the offsite electrical power system and the onsite AC electrical power system. Since power system redundancy is provided by two diverse sources of power, however, the reliability of the power systems in this Condition may appear higher than that in Condition C (loss of both required offsite circuits). This difference in reliability is offset by the susceptibility of this power system configuration to a single bus or switching failure. The 12 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

E.1

With two or more DGs inoperable, the remaining standby AC sources are not adequate to satisfy analysis assumptions. Thus, with an assumed loss of offsite electrical power, insufficient standby AC sources are available to power the minimum required ESF functions. Since the offsite electrical power system is the only source of AC power for this level of degradation, the risk associated with continued operation for a very short time could be less than that associated with an immediate controlled shutdown (the immediate shutdown could cause grid instability, which could result in a total loss of AC power). Since any inadvertent generator trip could also result in a total loss of offsite AC power, however, the time allowed for continued operation is severely restricted. The intent here is to avoid the risk associated with an immediate controlled shutdown and to minimize the risk associated with this level of degradation.

According to Reference 6, with two or more DGs inoperable, operation may continue for a period that should not exceed 2 hours.

F.1 and F.2

If the inoperable AC electric power sources cannot be restored to OPERABLE status within the required Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To

BASES

ACTIONS

F.1 and F.2 (continued)

achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging plant systems.

G.1 and H.1

Conditions G and H correspond to a level of degradation in which all redundancy in the AC electrical power supplies has been lost or a loss of safety function has already occurred. Therefore, no additional time is justified for continued operation. The unit is required by LCO 3.0.3 to commence a controlled shutdown.

SURVEILLANCE REQUIREMENTS

The AC sources are designed to permit inspection and testing of all important areas and features, especially those that have a standby function, in accordance with 10 CFR 50, Appendix A, GDC 18 (Ref. 1). Periodic component tests are supplemented by extensive functional tests during refueling outages (under simulated accident conditions). The SRs for demonstrating the OPERABILITY of the DGs are consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3),and Regulatory Guide 1.137 (Ref. 8).

Where the SRs discussed herein specify voltage and frequency tolerances, the following is applicable. The minimum steady state output voltage of 422 V is the value determined to be acceptable in the analysis of the degraded grid condition. This value allows for voltage drop to the terminals of 480 V motors. It also allows for voltage drops to motors and other equipment down through the 120 V level where minimum operating voltage is also usually specified as 90% of name plate rating. The specified maximum steady state output voltage of 500 V is equal to the maximum operating voltage specified for 480 V circuit breakers. The specified minimum and maximum frequencies of the DG are 58.8 Hz and 61.2 Hz, respectively. These values are

BASES

SURVEILLANCE REQUIREMENTS (continued)

equal to ± 2% of the 60 Hz nominal frequency and are derived from the recommendations given in Regulatory Guide 1.9 (Ref. 3).

SR 3.8.1.1

This SR ensures proper circuit continuity for the offsite AC electrical power supply to the onsite distribution network and availability of offsite AC electrical power. The breaker alignment verifies that each breaker is in its correct position to ensure that distribution buses and loads are connected to their preferred power source, and that appropriate independence of offsite circuits is maintained. Portions of this SR are satisfied by telephone communication with Consolidated Edison personnel capable of confirming the status of the offsite circuits. The 7 day Frequency is adequate since breaker position is not likely to change without the operator being aware of it and because 6.9 kV bus status and 13.8 kV circuit status are displayed in the control room.

SR 3.8.1.2

These SRs help to ensure the availability of the standby electrical power supply to mitigate DBAs and transients and to maintain the unit in a safe shutdown condition.

To minimize the wear on moving parts that do not get lubricated when the engine is not running, these SRs are modified by a Note to indicate that all DG starts for these Surveillances may be preceded by an engine prelube period.

For the purposes of SR 3.8.1.2, the DGs are started from standby conditions. Standby conditions for a DG mean that the diesel engine coolant and oil are being continuously circulated and temperature is being maintained consistent with manufacturer recommendations.

SR 3.8.1.2 requires that, at a 31 day Frequency, the DG starts from standby conditions and achieves required voltage and frequency within 10 seconds. The 10 second start requirement

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.2 (continued)

supports the assumptions of the design basis LOCA analysis in the FSAR, Chapter 14 (Ref. 5).

The normal 31 day Frequency for SR 3.8.1.2 is consistent with Regulatory Guide 1.9 (Ref. 3). This Frequency provides adequate assurance of DG OPERABILITY, while minimizing degradation resulting from testing. DGs have redundant air start motors and both air start motors are actuated by both channels of the start logic. The DG is OPERABLE when either air start motor is OPERABLE; however, this SR will not demonstrate that both of the air start motors are independently capable of starting the DG. If an air start motor is not capable of performing its intended function, a DG is inoperable until a timed start is conducted using the remaining air start motor. Alternately, this SR may be performed using one air start motor (i.e., redundant air start motor isolated) on a staggered basis to ensure that the DG will start with either air start motor.

SR 3.8.1.3

This Surveillance verifies that the DGs are capable of synchronizing with the offsite electrical system and accepting loads approximating the maximum expected accident loads. A minimum run time of 60 minutes is required to stabilize engine temperatures, while minimizing the time that the DG is connected to the offsite source.

Although no power factor requirements are established by this SR, the DG is normally operated at a power factor between 0.8 lagging and 1.0. The 0.8 value is the design rating of the machine, while the 1.0 is an operational limitation to ensure circulating currents are minimized. The load band is provided to avoid routine overloading of the DG. Routine overloading may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY.

The 31 day Frequency for this Surveillance is consistent with Regulatory Guide 1.9 (Ref. 3).

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.3 (continued)

This SR is modified by four Notes. Note 1 indicates that diesel engine runs for this Surveillance may include gradual loading, as recommended by the manufacturer, so that mechanical stress and wear on the diesel engine are minimized. Note 2 states that momentary transients, because of changing bus loads, do not invalidate this test. Similarly, momentary power factor transients above the limit do not invalidate the test. Note 3 indicates that this Surveillance should be conducted on only one DG at a time in order to avoid common cause failures that might result from offsite circuit or grid perturbations. Note 4 stipulates a prerequisite requirement for performance of this SR. A successful DG start must precede this test to credit satisfactory performance.

SR 3.8.1.4

This SR provides verification that the level of fuel oil in the day tank is at or above the level at which fuel oil is automatically added. The level is expressed as an equivalent volume in gallons, and is selected to ensure adequate fuel oil for approximately 1 hour of DG operation at full load.

The 31 day Frequency is adequate to assure that a sufficient supply of fuel oil is available, since low level alarms are provided and facility operators would be aware of any large uses of fuel oil during this period.

SR 3.8.1.5

Microbiological fouling is a major cause of fuel oil degradation. There are numerous bacteria that can grow in fuel oil and cause fouling, but all must have a water environment in order to survive. Removal of water from the fuel oil day tanks once every 31 days eliminates the necessary environment for bacterial survival. This is the most effective means of controlling microbiological fouling. In addition, it eliminates the potential for water entrainment in the fuel oil during DG operation. Water may come from any of several sources, including

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.5 (continued)

condensation, ground water, rain water, contaminated fuel oil, and breakdown of the fuel oil by bacteria. Frequent checking for and removal of accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. The Surveillance Frequencies are consistent with Regulatory Guide 1.137 (Ref. 8). This SR is for preventative maintenance. The presence of water does not necessarily represent failure of this SR, provided the accumulated water is removed during the performance of this Surveillance.

SR 3.8.1.6

This Surveillance demonstrates that each required fuel oil transfer pump operates and transfers fuel oil from its associated storage tank to its associated day tank. This is required to support continuous operation of standby power sources. This Surveillance provides assurance that the fuel oil transfer pump is OPERABLE, the fuel oil piping system is intact, the fuel delivery piping is not obstructed, and the controls and control systems for automatic fuel transfer systems are OPERABLE.

The design of fuel transfer systems is such that pumps operate automatically or must be started manually in order to maintain an adequate volume of fuel oil in the day tanks during or following DG testing. Therefore, a 31 day Frequency is appropriate. Since proper operation of fuel transfer systems is an inherent part of DG OPERABILITY, the Frequency of this SR is consistent with the 31 day Frequency for verification of DG operability.

SR 3.8.1.7

Transfer of the offsite power supply from the normal offsite circuit to the alternate offsite circuit demonstrates the OPERABILITY of the alternate circuit distribution network to power the shutdown loads. The 24 month Frequency of the Surveillance is based on engineering judgment, taking into consideration the unit conditions required to perform the

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.7 (continued)

Surveillance, and is intended to be consistent with expected fuel cycle lengths. Operating experience has shown that these components usually pass the SR when performed. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.8.1.8

Verification that 6.9 kV buses 2 and 3 will auto transfer (fast transfer) from the Unit Auxiliary transformer to 6.9 kV buses 5 and 6 (i.e. station auxiliary transformer) following a loss of voltage on 6.9 kV buses 2 and 3 is needed to confirm the Operability of a function assumed to operate to provide offsite power to safeguards power train 2A/3A following a trip of the main generator.

An actual demonstration of this feature requires the tripping of the main generator while the reactor is at power with the main generator supplying 6.9 kV buses 2 and 3. This will cause perturbations to the electrical distribution systems that could challenge unit safety systems during a plant shutdown. Therefore, in lieu of actually initiating a circuit transfer, testing that adequately shows the capability of the transfer is acceptable. This transfer testing may include any sequence of sequential, overlapping, or total steps so that the entire transfer sequence is verified. The 24 month Frequency is based on engineering judgement taking into consideration the plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle length.

This SR is modified by two Notes. The reason for Note 1 is that, during operation with the reactor critical, performance of this SR could cause perturbations to the electrical distribution systems that could challenge unit safety systems. Credit may be taken for unplanned events that satisfy this SR. As stated in Note 2, this SR is only required to be met when the 138 kV offsite circuit is supplying 6.9 kV buses 5 and 6 because, if the

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.8 (continued)

13.8 kV circuit is supplying 6.9 kV buses 5 and 6, then the feature tested by this SR is required to be disabled.

SR 3.8.1.9

This Surveillance demonstrates that DG noncritical protective functions are bypassed on a loss of voltage signal concurrent with an ESF actuation test signal, and critical protective functions (engine overspeed, low lube oil pressure, and engine overcrank) trip the DG to avert substantial damage to the DG unit. The noncritical trips are bypassed during DBAs and provide an alarm on an abnormal engine condition. This alarm provides the operator with sufficient time to react appropriately. The DG availability to mitigate the DBA is more critical than protecting the engine against minor problems that are not immediately detrimental to emergency operation of the DG.

The 24 month Frequency is based on engineering judgment, taking into consideration unit conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths. Operating experience has shown that these components usually pass the SR. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.8.1.10

IEEE-387-1995 (Ref. 9) requires demonstration once per 24 months that the DGs can start and run continuously at full load capability for an interval of not less than 8 hours, ≥ 105 minutes of which is at a load equivalent to 110% of the continuous duty rating and the remainder of the time at a load equivalent to the continuous duty rating of the DG. The DG starts for this Surveillance can be performed either from standby or hot conditions. The provisions for prelubricating and warmup, discussed in SR 3.8.1.2, and for gradual loading, discussed in SR 3.8.1.3, are applicable to this SR.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.10 (continued)

In order to ensure that the DG is tested under load conditions that are as close to design conditions as possible, testing must be performed using a power factor of $\leq$ 0.9. This power factor is chosen to be representative of the actual design basis inductive loading that the DG would experience. The load band is provided to avoid routine overloading of the DG. Routine overloading may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY.

The 24 month Frequency is consistent with the recommendations of Ref. 9, and takes into consideration unit conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This Surveillance is modified by a note that states that momentary transients due to changing bus loads do not invalidate this test. Similarly, momentary power factor transients above the power factor limit will not invalidate the test.

SR 3.8.1.11

Under accident conditions with concurrent loss of offsite power, loads are sequentially connected to the bus by individual load timers to prevent overloading of the DGs due to high motor starting currents. The design load sequence time interval tolerance ensures that sufficient time exists for the DG to restore frequency and voltage prior to applying the next load and that safety analysis assumptions regarding ESF equipment time delays are not violated. Reference 2 provides a summary of the automatic loading of ESF buses.

The Frequency of 18 months is based on engineering judgment, taking into consideration operating experience that has shown that these components usually pass the SR. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.11 (continued)

This SR is modified by a Note that specifies that load timers associated with equipment that has automatic initiation capability disabled are not required to be OPERABLE. This note is needed because these time delay relays affect the OPERABILITY of both the AC sources (offsite power and DG) and the specific load that the relay starts. If a timer fails to start a required load or starts the load later than assumed in the analysis, then the required load is not OPERABLE. If a timer starts the load outside the design interval (early or late), then the DG and offsite source are not OPERABLE because overlap of equipment starts may cause an offsite source to exceed limits for voltage or current or a DG to exceed limits for voltage, current or frequency. Therefore, when an individual load sequence timer is not OPERABLE, it is conservative to disable the automatic initiation capability of that component rather than declare the associated DG inoperable because of the following: the potential for adverse impact on the DG by simultaneous start of ESF equipment is eliminated; all other loads powered from the safeguards power train are available to respond to the event; and, the load with the inoperable timer remains available for a manual start after the one minute completion of the normal starting sequence.

SR 3.8.1.12

In the event of a DBA coincident with a loss of offsite power, the DGs are required to supply the necessary power to ESF systems so that the fuel, RCS, and containment design limits are not exceeded.

This Surveillance demonstrates the DG operation during a loss of offsite power actuation test signal in conjunction with an ESF actuation signal. This SR verifies all actions encountered from an ESF signal concurrent with the loss of offsite power, including shedding of the nonessential loads and energization of the emergency buses and respective loads from the DG. It further demonstrates the capability of the DG to automatically achieve the required voltage and frequency within the specified time.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.12 (continued)

The DG autostart time of 10 seconds is derived from requirements of the accident analysis to respond to a design basis large break LOCA. The Surveillance should be continued for a minimum of 5 minutes in order to demonstrate that all starting transients have decayed and stability is achieved.

The requirement to verify the connection and power supply of permanent and auto-connected loads is intended to satisfactorily show the relationship of these loads to the DG loading logic. In certain circumstances, many of these loads cannot actually be connected or loaded without undue hardship or potential for undesired operation. For instance, Emergency Core Cooling Systems (ECCS) injection valves are not desired to be stroked open, or high pressure injection systems are not capable of being operated, or residual heat removal (RHR) systems performing a decay heat removal function are not desired to be realigned to the ECCS mode of operation.

In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the DG system to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

The Frequency of 24 months takes into consideration unit conditions required to perform the Surveillance and is intended to be consistent with an expected fuel cycle length of 24 months.

This SR is modified by three Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil and temperature maintained and lube oil continuously circulated consistent with manufacturer recommendations for DGs.

The reason for Note 2 is that the performance of the Surveillance would remove required offsite circuits from service, perturb the electrical distribution system, and challenge safety systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.12 (continued)

The reason for Note 3 is to allow the SR to be conducted with only one safeguards train at a time or with two or three safeguards trains concurrently. Allowing the LOOP/LOCA test to be conducted using one safeguards power train and one DG at a time is acceptable because the safeguards power trains are designed to respond to this event independently. Therefore, an individual test for each safeguards power train will provide an adequate verification of plant response to this event.

Allowing the LOOP/LOCA test to be conducted with more than one safeguards trains concurrently is acceptable for the following reasons: plant status is established to minimize impact on core cooling and in accordance with LCO 3.8.2 just as if no DGs are OPERABLE during the performance of this test; and, extensive experience with this test indicates that loss of all AC due to common failure modes and/or undetected interdependence among DGs is not likely.

SR 3.8.1.13

This Surveillance demonstrates that the DG starting independence has not been compromised. Also, this Surveillance demonstrates that each engine can achieve proper speed within the specified time when the DGs are started simultaneously.

The 10 year Frequency is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3).

This SR is modified by two Notes. The reason for Note 1 is to minimize wear on the DG during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil continuously circulated and temperature maintained consistent with manufacturer recommendations. The reason for Note 2 is to allow SR 3.8.1.12 to satisfy the requirements of this SR if SR 3.8.1.12 is performed with more than one safeguards power train concurrently.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.2 AC Sources – Shutdown

BASES

BACKGROUND

A description of the AC sources is provided in the Bases for LCO 3.8.1, "AC Sources – Operating."

APPLICABLE SAFETY ANALYSES

The OPERABILITY of the minimum AC sources during MODES 5 and 6 and during movement of irradiated fuel assemblies ensures that:

a. The unit can be maintained in the shutdown or refueling condition for extended periods;

b. Sufficient instrumentation and control capability is available for monitoring and maintaining the unit status; and

c. Adequate AC electrical power is provided to mitigate events postulated during shutdown, such as a fuel handling accident.

In general, when the unit is shut down, the Technical Specifications requirements ensure that the unit has the capability to mitigate the consequences of postulated accidents. However, assuming a single failure and concurrent loss of all offsite or all onsite power is not required. The rationale for this is based on the fact that many Design Basis Accidents (DBAs) that are analyzed in MODES 1, 2, 3, and 4 have no specific analyses in MODES 5 and 6. Worst case bounding events are deemed not credible in MODES 5 and 6 because the energy contained within the reactor pressure boundary, reactor coolant temperature and pressure, and the corresponding stresses result in the probabilities of occurrence being significantly reduced or eliminated, and in minimal consequences. These deviations from DBA analysis assumptions and design requirements during shutdown conditions are allowed by the LCO for required systems.

BASES

APPLICABLE SAFETY ANALYSES (continued)

During MODES 1, 2, 3, and 4, various deviations from the analysis assumptions and design requirements are allowed within the Required Actions. This allowance is in recognition that certain testing and maintenance activities must be conducted provided an acceptable level of risk is not exceeded. During MODES 5 and 6, performance of a significant number of required testing and maintenance activities is also required. In MODES 5 and 6, the activities are generally planned and administratively controlled. Relaxations from MODE 1, 2, 3, and 4 LCO requirements are acceptable during shutdown modes based on:

a. The fact that time in an outage is limited. This is a risk prudent goal as well as a utility economic consideration.

b. Requiring appropriate compensatory measures for certain conditions. These may include administrative controls, reliance on systems that do not necessarily meet typical design requirements applied to systems credited in operating MODE analyses, or both.

c. Prudent utility consideration of the risk associated with multiple activities that could affect multiple systems.

d. Maintaining, to the extent practical, the ability to perform required functions (even if not meeting MODE 1, 2, 3, and 4 OPERABILITY requirements) with systems assumed to function during an event.

In the event of an accident during shutdown, this LCO ensures the capability to support systems necessary to avoid immediate difficulty, assuming either a loss of all offsite power or a loss of all onsite diesel generator (DG) power.

The AC sources satisfy Criterion 3 of 10 CFR 50.36.

LCO

One offsite circuit capable of supplying the onsite power distribution subsystem(s) of LCO 3.8.10, "Distribution Systems – Shutdown," ensures that all required loads are powered

BASES

LCO (continued)

from offsite power. Two OPERABLE DGs, associated with the distribution system train required to be OPERABLE by LCO 3.8.10, ensures a diverse power source is available to provide electrical power support, assuming a loss of the offsite circuit. Together, OPERABILITY of the required offsite circuit and DGs ensures the availability of sufficient AC sources to operate the unit in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents).

The qualified offsite circuit must be capable of maintaining rated frequency and voltage, and accepting required loads during an accident, while connected to the Engineered Safety Feature (ESF) bus(es). Qualified offsite circuits are those that are described in the Bases of LCO 3.8.1, AC Sources - Operating, except that safeguards power trains may be cross connected when in MODES 5 and 6.

The DGs must be capable of starting, accelerating to rated speed and voltage, and connecting to its respective ESF bus on detection of bus undervoltage. This sequence must be accomplished within 10 seconds. The DG must be capable of accepting required loads within the assumed loading sequence intervals, and continue to operate until offsite power can be restored to the ESF buses.

Proper sequencing of loads, including tripping of nonessential loads, is a required function for DG OPERABILITY.

It is acceptable for safeguards power trains to be cross tied during shutdown conditions, allowing a single offsite power circuit to supply all required trains.

APPLICABILITY

The AC sources required to be OPERABLE in MODES 5 and 6 and during movement of irradiated fuel assemblies provide assurance that:

BASES

APPLICABILITY (continued)

a. Systems to provide adequate coolant inventory makeup are available for the irradiated fuel assemblies in the core;

b. Systems needed to mitigate a fuel handling accident are available;

c. Systems necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition or refueling condition.

The AC power requirements for MODES 1, 2, 3, and 4 are covered in LCO 3.8.1.

ACTIONS

A.1

An offsite circuit would be considered inoperable if it were not available to one required safeguards power train. Although two safeguards power trains may be required by LCO 3.8.10, the one train with offsite power available may be capable of supporting sufficient required features to allow continuation of CORE ALTERATIONS and fuel movement. By the allowance of the option to declare required features inoperable, with no offsite power available, appropriate restrictions will be implemented in accordance with the affected required features LCO's ACTIONS.

A.2.1, A.2.2, A.2.3 and A.2.4

With the offsite circuit not available to all required trains, the option would still exist to declare all required features inoperable. Since this option may involve undesired administrative efforts, the allowance for sufficiently conservative actions is made. It is, therefore, required to suspend CORE ALTERATIONS, movement of irradiated fuel assemblies, and operations involving positive reactivity additions. The Required Action to suspend positive reactivity additions does not

BASES

ACTIONS

A.2.1, A.2.2, A.2.3 and A.2.4 (continued)

preclude actions to maintain or increase reactor vessel inventory provided the required SDM is maintained.

Suspension of these activities does not preclude completion of actions to establish a safe conservative condition. These actions minimize the probability or the occurrence of postulated events. It is further required to immediately initiate action to restore the required AC sources and to continue this action until restoration is accomplished in order to provide the necessary AC power to the unit safety systems.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required AC electrical power sources should be completed as quickly as possible in order to minimize the time during which the unit safety systems may be without sufficient power.

Pursuant to LCO 3.0.6, the Distribution System's ACTIONS would not be entered even if all AC sources to it are inoperable, resulting in de-energization. Therefore, the Required Actions of Condition A are modified by a Note to indicate that when Condition A is entered with no AC power to any required ESF bus, the ACTIONS for LCO 3.8.10 must be immediately entered. This Note allows Condition A to provide requirements for the loss of the offsite circuit, whether or not a train is de-energized. LCO 3.8.10 would provide the appropriate restrictions for the situation involving a de-energized bus.

B.1

A DG would be considered inoperable if it could not support its associated safeguards power train. Although two DGs are required, one OPERABLE DG and its associated safeguards power train may be capable of supporting sufficient required features to allow continuation of CORE ALTERATIONS and fuel movement. By the allowance of the option to declare required features inoperable, with no DG available, appropriate restrictions will be implemented in accordance with the affected required features LCO's ACTIONS.

BASES

ACTIONS (continued)

B.2.1, B.2.2, B.2.3 and B.2.4

With one required DG inoperable, the option would still exist to declare inoperable all required features supported by the inoperable DG. Since this option may involve undesired administrative efforts, the allowance for sufficiently conservative actions is made. Therefore, with one required DG inoperable, the option exists to suspend CORE ALTERATIONS, movement of irradiated fuel assemblies, and operations involving positive reactivity additions.

With two required DGs inoperable, the minimum required diversity of AC power sources is not available to any required features. Although the option would still exist to declare all required features inoperable, the requirements imposed by the affected required features LCO's ACTIONS would be equivalent to the option provided by Required Actions B.2.1, B.2.2 and B.2.3. Therefore, with two required DGs inoperable, it is required to suspend CORE ALTERATIONS, movement of irradiated fuel assemblies, and operations involving positive reactivity additions.

With one or more required DGs inoperable, the Required Action to suspend positive reactivity additions does not preclude actions to maintain or increase reactor vessel inventory provided the required SDM is maintained. Additionally, Required Actions B.2.1, B.2.2 and B.2.3 do not preclude completion of actions to establish a safe conservative condition. These actions minimize the probability or the occurrence of postulated events.

Furthermore, Required Actions B.2.1, B.2.2 and B.2.3 are implemented, it is required to immediately initiate action to restore the required DG(s) and to continue this action until restoration is accomplished in order to provide the necessary AC power to the unit safety systems.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required AC electrical power sources should be completed as quickly as possible in order to minimize the time

BASES

ACTIONS

B.2.1, B.2.2, B.2.3 and B.2.4 (continued)

during which the unit safety systems may be without sufficient power.

SURVEILLANCE REQUIREMENTS

SR 3.8.2.1

SR 3.8.2.1 requires the SRs from LCO 3.8.1 that are necessary for ensuring the OPERABILITY of the AC sources in other than MODES 1, 2, 3, and 4. Surveillance tests that include features not required or not capable of functioning in the existing plant MODE or plant condition are satisfactory if all features required in the existing plant MODE or plant condition are tested and verified to be OPERABLE.

This SR is modified by a Note. The reason for the Note is to preclude requiring the OPERABLE DG(s) from being paralleled with the offsite power network or otherwise rendered inoperable during performance of SRs, and to preclude deenergizing a required 480 V ESF bus or disconnecting a required offsite circuit during performance of SRs. With limited AC sources available, a single event could compromise both the required circuit and the DG. It is the intent that these SRs must still be capable of being met, but actual performance is not required during periods when the DG and offsite circuit is required to be OPERABLE. Refer to the corresponding Bases for LCO 3.8.1 for a discussion of each SR.

REFERENCES

None.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.3 Diesel Fuel Oil and Starting Air

BASES

BACKGROUND

Fuel oil for the safeguards DGs is stored in three 7,700 gallon DG fuel oil storage tanks located on the south side of the Diesel Generator Building. The offsite DG fuel oil reserve is maintained in two 30,000 gallon tanks located in the Indian Point 1 Superheater Building and/or a 200,000 gallon tank in the Buchanan Substation which is located in close proximity to the IP3 site. The IP3 offsite fuel oil reserve is maintained by the operators of IP2, Consolidated Edison Company, in accordance with formal agreements with NYPA. The IP3 offsite DG fuel oil reserve is normally stored in the same tanks used to store the IP2 offsite DG fuel oil reserve.

Sufficient fuel for at least 48 hours of minimum safeguards equipment operation is available when any two of the DG fuel oil storage tanks are available and contain 6671 gallons (5,891 usable gallons) of fuel oil. The maximum DG loadings for design basis transients that actuate safety injection are summarized in FSAR 8.2 (Ref. 1). These transients include large and small break loss of coolant accidents (LOCA), main steamline break and steam generator tube rupture (SGTR).

The three DG fuel oil storage tanks are filled through a common fill line that is equipped with a truck hose connection and a shutoff valve at each tank. The overflow from any DG fuel oil storage tank will cascade into an adjacent tank. Each DG fuel oil storage tank is equipped with a single vertical fuel oil transfer pump that discharges to either the normal or emergency header. Either header can be used to fill the day tank at each diesel. Each DG fuel oil storage tank has an alarm that sounds in the control room when the level in the tank drops to approximately 6,717 gallons. Each tank is also equipped with a sounding connection and a level indicator.

Each emergency diesel is equipped with a 175-gallon day tank with an operating level that provides sufficient fuel for approximately one hour of DG operation. A decrease in day tank level to approximately 115 gallons (65% full) will cause the

BASES

BACKGROUND (Continued)

normal and emergency fill valves on that day tank to open and the transfer pump in the corresponding DG fuel oil storage tank to start. Once started, the pump will continue to run until that day tank is filled. However, any operating transfer pump will fill any day tank with a normal or emergency fill valve that is open. When a day tank is at approximately 158 gallons (90% full), a switch initiates closing of the day tank normal and emergency fill valves.

Technical Specifications require sufficient fuel oil to operate 2 of the 3 required DGs at minimum safeguards load for 7 days. The Technical Specification required volume of fuel oil includes the 30,026 gallons of usable fuel oil in the reserve tanks, 11,782 usable gallons in two DG fuel oil storage tanks (assuming a failure makes the oil in the third DG fuel oil storage tank unavailable), and 230 gallons in two day tanks (assuming a failure makes the oil in the day tank associated with the third DG unavailable).

If the DGs require fuel oil from the fuel oil reserve tank(s), the fuel oil will be transported by truck to the DG fuel oil storage tanks. A truck with appropriate hose connections and capable of transporting oil is available either on site or at the Buchanan Substation. Commercial oil supplies and trucking facilities are also available in the vicinity of the plant.

For proper operation of the standby DGs, it is necessary to ensure the proper quality of the fuel oil. Requirements for DG fuel oil testing methodology, frequency, and acceptance criteria are maintained in the program required by Specification 5.5.12, Diesel Fuel Oil Testing Program.

Each DG has an air start system with adequate capacity for four successive start attempts on the DG without recharging the air start receiver(s). The air starting system is designed to shutdown and lock out any engine which does not start during the initial start attempt so that only enough air for one automatic start is used. This conserves air for subsequent DG start attempts.

BASES

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the FSAR, Chapter 14 (Ref. 3), assume Engineered Safety Feature (ESF) systems are OPERABLE. The DGs are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that fuel, Reactor Coolant System and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.4, Reactor Coolant System (RCS); and Section 3.6, Containment Systems.

Since diesel fuel oil and the air start subsystem support the operation of the standby AC power sources, they satisfy Criterion 3 of 10 CFR 50.36.

LCO

Stored diesel fuel oil is required to have sufficient supply for 7 days of operation for 2 of 3 DGs at minimum safeguards load. Fuel oil is also required to meet specific standards for quality. This requirement, in conjunction with an ability to obtain replacement supplies within 7 days, supports the availability of DGs required to shut down the reactor and to maintain it in a safe condition for an anticipated operational occurrence (AOO) or a postulated DBA with loss of offsite power. DG day tank fuel requirements, as well as transfer capability from the storage tank to the day tank, are addressed in LCO 3.8.1, "AC Sources – Operating," and LCO 3.8.2, "AC Sources – Shutdown."

The starting air system is required to have a minimum capacity for four successive DG start attempts without recharging the air start receivers.

APPLICABILITY

The AC sources (LCO 3.8.1 and LCO 3.8.2) are required to ensure the availability of the required power to shut down the reactor and maintain it in a safe shutdown condition after an AOO or a postulated DBA. Since stored diesel fuel oil and the starting air subsystem support LCO 3.8.1 and LCO 3.8.2, stored diesel fuel

BASES

APPLICABILITY (continued)

oil and starting air are required to be within limits when the associated DG is required to be OPERABLE.

ACTIONS

The ACTIONS Table is modified by a Note indicating that separate Condition entry is allowed for each DG. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable DG subsystem. Complying with the Required Actions for one inoperable DG subsystem may allow for continued operation, and subsequent inoperable DG subsystem(s) are governed by separate Condition entry and application of associated Required Actions.

A.1

In this Condition, the requirements of SR 3.8.3.2.a are not met. Therefore, a DG will not be able to support 48 hours of continuous operation at minimum safeguards load and replenishment of the DG fuel oil storage tanks will be required in less than 48 hours following an accident. The DG associated with the DG fuel oil storage tank not within limits must be declared inoperable immediately because replenishment of the DG fuel oil storage tank requires that fuel be transported from the offsite DG fuel oil reserve by truck and the volume of fuel oil remaining in the DG fuel oil storage tank may not be sufficient to allow continuous DG operation while the fuel transfer is planned and conducted under accident conditions.

This Condition is preceded by a Note stating that Condition A is applicable only in MODES 1, 2, 3 and 4. This Note provides recognition that reduced DG loading required to respond to events in MODES 5 and 6 significantly reduces the amount of fuel oil required in the DG fuel oil storage tanks when in these MODES.

B.1

In this Condition, the requirements of SR 3.8.3.2.b are not met. With less than the total required minimum fuel oil in one or more DG fuel oil storage tanks, the two DGs required to be operable in

BASES

ACTIONS

B.1 (continued)

MODES 5 and 6 and during movement of irradiated fuel may not have sufficient fuel oil to support continuous operation while a fuel transfer from the offsite DG fuel oil reserve or from another offsite source is planned and conducted under accident conditions.

This condition requires that all DGs be declared inoperable immediately because minimum fuel oil level requirements in SR 3.8.3.2.b is a condition of Operability of all DGs when in the specified MODES.

This Condition is preceded by a Note stating that Condition B is applicable only in MODES 5 and 6 and during the movement of irradiated fuel. This Note provides recognition that reduced DG loading required to respond to events in MODES 5 and 6 significantly reduces the amount of fuel oil required in the DG fuel oil storage tanks when in these MODES.

C.1

In this Condition, the fuel oil remaining in the offsite DG fuel oil reserve is not sufficient to operate 2 of the 3 DGs at minimum safeguards load for 7 days. Therefore, all 3 DGs are declared inoperable immediately.

This Condition is preceded by a Note stating that Condition D is applicable only in MODES 1, 2, 3 and 4 because the offsite DG fuel oil reserve is required to be available only in these MODES. This Note provides recognition that reduced DG loading required to respond to events in MODES 5 and 6 significantly reduces the amount of fuel oil required when in these MODES.

D.1

This Condition is entered as a result of a failure to meet the acceptance criterion of SR 3.8.3.3 when the DG fuel oil storage tanks are verified to have particulate within the allowable value in Specification 5.5.12, Diesel Fuel Oil Testing Program. Normally, trending of particulate levels allows sufficient time to correct high particulate levels prior to reaching the limit of

BASES

ACTIONS

D.1 (continued)

acceptability. Poor sample procedures (bottom sampling), contaminated sampling equipment, and errors in laboratory analysis can produce failures that do not follow a trend. Since the presence of particulates does not mean failure of the fuel oil to burn properly in the diesel engine, and particulate concentration is unlikely to change significantly between Surveillance Frequency intervals, and proper engine performance has been recently demonstrated (within 31 days), it is prudent to allow a brief period prior to declaring the associated DG inoperable. The 7 day Completion Time allows for further evaluation, resampling and re-analysis of the DG fuel oil.

E.1

If the properties of new fuel oil are determined not to be within the requirements established by Specification 5.5.12, Diesel Fuel Oil Testing Program, after the fuel oil has been added to the DG fuel oil storage tanks, then a period of 30 days is allowed to restore the properties of the fuel oil in the DG fuel oil storage tank to within the limits established by Specification 5.5.12. This period provides sufficient time to test the stored fuel oil to determine that the new fuel oil, when mixed with previously stored fuel oil, remains acceptable, or to restore the stored fuel oil properties. This restoration may involve feed and bleed procedures, filtering, or combinations of these procedures. Even if a DG start and load was required during this time interval and the fuel oil properties were outside limits, there is a high likelihood that the DG would still be capable of performing its intended function.

F.1

Fuel oil from the offsite DG fuel oil reserve will be added to the DG fuel oil fuel oil storage tanks within the first 48 hours following an event in conjunction with a sustained loss of offsite power. Therefore, the properties of the fuel oil in the offsite reserve must be maintained within the limits established by Specification 5.5.12, Diesel Fuel Oil Testing Program. Failure to maintain the offsite DG fuel oil reserve within these limits may adversely impact DG operation of all three DGs at some

BASES

ACTIONS

F.1 (continued)

point following addition of the reserves to the DG fuel oil storage tanks. Therefore, if the offsite DG fuel oil reserve is not restored to within these limits within the specified Completion Time, then all three DGs must be declared inoperable.

Restoration of properties to within required limits may be performed by using the fuel in the gas turbine peaking units and replacing it with fuel within required limits or by the methods described in the Bases for Condition E.

The Completion Time of 30 days for the restoration of fuel oil properties to within limits is acceptable because the DG fuel oil storage tanks contain sufficient fuel for a minimum of 48 hours DG operation at minimum safeguards load. The Completion Time is acceptable because there is a high likelihood that the DG would still be capable of meeting requirements for starting and endurance even if fuel oil from the offsite DG fuel oil reserve must be added to the DG fuel oil tanks during the time interval the fuel oil properties are outside specified limits. Additionally, IP3 is located in an area where compatible fuel oil is expected to be readily available.

G.1

With starting air receiver pressure < 250 psig, sufficient capacity for four successive DG start attempts does not exist. However, as long as the receiver pressure is ≥ 90 psig, there is adequate capacity for at least one start attempt, and the DG can be considered OPERABLE while the air receiver pressure is restored to the required limit. A period of 48 hours is considered sufficient to complete restoration to the required pressure prior to declaring the DG inoperable. This period is acceptable based on the remaining air start capacity, the fact that most DG starts are accomplished on the first attempt, and the low probability of an event during this brief period. Entry into Condition G is not required when air receiver pressure is less than required limits while the DG is operating following a successful start.

BASES

ACTIONS (continued)

H.1

With a Required Action and associated Completion Time not met, or one or more DG's fuel oil or starting air subsystem not within limits for reasons other than addressed by Conditions A through G, the associated DG may be incapable of performing its intended function and must be immediately declared inoperable.

SURVEILLANCE REQUIREMENTS

SR 3.8.3.1

This SR provides verification that there is an adequate inventory of fuel oil in the offsite DG fuel oil reserve to support 2 DGs at minimum safeguards load for 7 days assuming requirements for the DG fuel oil storage tanks and day tanks are met. The 7 day duration with 2 of the 3 DGs at minimum safeguards load is sufficient to place the unit in a safe shutdown condition and to bring in replenishment fuel from a commercial source.

The 24 hour Frequency is needed because the DG fuel oil reserve is stored in fuel oil tanks that support the operation of gas turbine peaking units that are not under IP3 control. Specifically, the 30,026 gallons needed to support 7 days of DG operation is maintained in two 30,000 gallon tanks located in the Indian Point 1 Superheater Building and/or a 200,000 gallon tank in the Buchanan Substation. Although the volume of fuel oil required to support IP3 DG operability is designated as for the exclusive use of IP3, the fact that the oil in the storage tanks is used for purposes other than IP3 DGs and oil consumption is not under the direct control of IP3 operators warrants frequent verification that required offsite DG fuel oil reserve volume is being maintained.

SR 3.8.3.2

SR 3.8.3.2.a provides verification when in MODES 1, 2, 3, and 4, that there is an adequate inventory of fuel oil in the storage

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.3.2 (continued)

DG fuel oil tanks to support each DG's operation for at least 48 hours of operation of minimum safeguards equipment when any two of the DG fuel oil storage tanks are available and 5,891 gallons of usable fuel oil is contained in each tank.

SR 3.8.3.2.b provides verification when in MODES 5 and 6 and during movement of irradiated fuel that the minimum required fuel oil for operation in these MODES is available in one or more DG fuel oil storage tanks. The minimum required volume of fuel oil takes into account the reduced DG loading required to respond to events in MODES 5 and 6 is sufficient to support the two DGs required to be operable in MODES 5 and 6 and during movement of irradiated fuel while a fuel transfer from the offsite DG fuel oil reserve or from another offsite source is planned and conducted under accident conditions.

This minimum volume required by SR 3.8.3.2.a and SR 3.8.3.2.b is the usable volume and does not include allowances for fuel not usable due to the fuel oil transfer pump cutoff switch (760 gallons) and the required safety margin (20 gallons per tank). If the installed level indicators are used to measure tank volume, an additional allowance of 50 gallons for instrument uncertainty associated with the level indicators must be included. Appropriate adjustments are required for SR 3.8.3.2.b if the required volume is found in more than one DG fuel oil storage tank.

The 31 day Frequency is adequate to ensure that a sufficient supply of fuel oil is available, since low level alarms are provided and unit operators would be aware of any large uses of fuel oil during this period.

SR 3.8.3.3

This surveillance verifies that the properties of new and stored fuel oil meet the acceptance criteria established by Specification 5.5.12, "Diesel Fuel Oil Testing Program." Specific sampling and testing requirements for diesel fuel oil

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.3.3 (continued)

in accordance with applicable ASTM Standards are specified in the administrative program developed to ensure Specification.

New fuel oil is sampled prior to addition to the DG fuel oil storage tanks and stored fuel oil is periodically sampled from the DG fuel oil storage tanks. Requirements and acceptance criteria for fuel oil are divided into 3 parts as follows: a) tests of the sample of new fuel sample and acceptance criteria that must be met prior to adding the new fuel to the DG fuel oil storage tanks; b) tests of the sample of new fuel that may be completed after the fuel is added to the DG fuel oil storage tanks; and, c) tests of the fuel oil stored in the DG fuel oil storage tanks. The basis for each of these tests is described below.

The tests of the sample of new fuel and acceptance criteria that must be met prior to adding the new fuel to the DG fuel oil storage tanks are a means of determining that the new fuel oil is of the appropriate grade and has not been contaminated with substances that would have an immediate, detrimental impact on diesel engine combustion. If results from these tests are within acceptable limits, the fuel oil may be added to the storage tanks without concern for contaminating the entire volume of fuel oil in the storage tanks. The tests, limits, and applicable ASTM Standards needed to satisfy Specification 5.5.12 are listed in the administrative program developed to implement Specification 5.5.12.

Failure to meet any of the specified limits is cause for rejecting the new fuel oil, but does not represent a failure to meet the LCO because the fuel oil is not added to the storage tanks.

The tests of the sample of new fuel that may be completed after the fuel is added to the DG fuel oil storage tanks must be completed Within 31 days. The fuel oil is analyzed to establish that the other properties of the fuel oil meet the acceptance

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.3.3 (continued)

criteria of Specification 5.5.12. The 31 day period is acceptable because the fuel oil properties of interest, even if they were not within stated limits, would not have an immediate effect on DG operation. Failure to meet the specified acceptance criteria requires entry into Condition E and restoration of the quality of the fuel oil in the DG fuel oil storage tank within the associated Completion Time and explained in the Bases for Condition E. This Surveillance ensures the availability of high quality fuel oil for the DGs.

The periodic tests of the fuel oil stored in the DG fuel oil storage tanks verify that the length of time or conditions of storage has not degraded the fuel in a manner that could impact DG OPERABILITY. Fuel oil degradation during long term storage shows up as an increase in particulate, due mostly to oxidation. The presence of particulate does not mean the fuel oil will not burn properly in a diesel engine. The particulate can cause fouling of filters and fuel oil injection equipment, however, which can cause engine failure. Particulate concentrations must meet the acceptance criteria of Specification 5.5.12. It is acceptable to obtain a field sample for subsequent laboratory testing in lieu of field testing. Each DG fuel oil storage tank must be considered and tested separately.

The Frequency of this test takes into consideration fuel oil degradation trends that indicate that particulate concentration is unlikely to change significantly between Frequency intervals.

SR 3.8.3.4

The IP3 offsite fuel oil reserve is maintained by the operators of IP2, Consolidated Edison Company, in accordance with formal agreements with NYPA. The IP3 offsite DG fuel oil reserve is normally stored in the same tanks used to store the IP2 offsite DG fuel oil reserve. Fuel oil properties of new and stored fuel are controlled in accordance with IP2 Technical Specifications and FSAR in order to meet requirements for the Operability of IP2 and IP3 DGs.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.3.4 (continued)

Required testing of the properties of new and stored fuel in the offsite DG fuel oil reserve is performed by IP2 in accordance with programs established by Consolidated Edison Company. NYPA performs periodic verification that fuel oil stored in the offsite DG fuel oil reserve meet the requirements of Specification 5.5.12.

Failure to meet the specified acceptance criteria, whether identified by IP2 or IP3, requires entry into Condition F and restoration of the quality of the fuel oil in the offsite DG fuel oil reserve within the associated Completion Time and explained in the Bases for Condition F.

SR 3.8.3.5

This Surveillance ensures that, without the aid of the refill compressor, sufficient air start capacity for each DG is available. The system design requirements provide for a minimum of four engine starts without recharging. Failure of the engine to start within approximately 15 seconds indicates a malfunction at which point the overcrank relays terminate the start cycle. In this condition, sufficient starting air will still be available so that the DG can be manually started. The pressure specified in this SR is intended to reflect the lowest value at which the four starts can be accomplished.

The 31 day Frequency takes into account the capacity, capability, redundancy, and diversity of the AC sources and other indications available in the control room, including alarms, to alert the operator to below normal air start pressure.

SR 3.8.3.6

Microbiological fouling is a major cause of fuel oil degradation. There are numerous bacteria that can grow in fuel oil and cause fouling, but all must have a water environment in order to survive. Removal of water from the fuel storage tanks once every 92 days eliminates the necessary environment for bacterial

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.3.6 (continued)

survival. This is the most effective means of controlling microbiological fouling. In addition, it eliminates the potential for water entrainment in the fuel oil during DG operation. Water may come from any of several sources, including condensation, ground water, rain water, and contaminated fuel oil, and from breakdown of the fuel oil by bacteria. Frequent checking for and removal of accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. The Surveillance Frequencies are consistent with Regulatory Guide 1.137 (Ref. 2). This SR is for preventive maintenance. Unless the volume of water is sufficient that it could impact DG OPERABILITY, presence of water does not necessarily represent failure of this SR, provided the accumulated water is removed within 30 days of performance of the Surveillance.

REFERENCES

1. FSAR, Section 8.2.
2. Regulatory Guide 1.137.
3. FSAR, Chapter 14.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.4 DC Sources – Operating

BASES

BACKGROUND

The station DC electrical power system provides the AC emergency power system with control power. It also provides both motive and control power to selected safety related equipment and preferred 120 V AC vital instrument bus power (via inverters). As required by 10 CFR 50, Appendix A, GDC 17 (Ref. 1), the DC electrical power system is designed to have sufficient independence, redundancy, and testability to perform its safety functions, assuming a single failure. The DC electrical power system also is consistent with the recommendations of Regulatory Guide 1.6 (Ref. 2) and IEEE-308 (Ref. 3).

The 125 VDC electrical power system consists of four independent safety related DC electrical power subsystems (31, 32, 33 and 34). Each subsystem consists of one 125 VDC battery, the associated battery charger for each battery (except that battery charger 34 is not covered by this LCO), and all the associated control equipment and interconnecting cabling.

The four DC electrical power subsystems (batteries and associated chargers) 31, 32, 33, and 34 feed four main distribution power panels. DC electrical power subsystems 31, 32, and 33 supply DC control power to 480 volt buses Nos. 5A, 6A, and 2A/3A, respectively. The 480 volt switchgear bus sections that supply power to the safeguards equipment also receive DC control power from its associated DC electrical power subsystem. DC electrical power subsystem 34 does not provide DC control power to any equipment assumed to function to mitigate an accident.

The DC electrical power subsystems 31, 32, 33 and 34 also provide DC electrical power to the inverters, which in turn power the AC vital instrument buses. As a result, each of the four DC electrical power subsystems supports one of the four Reactor Protection System (RPS) Instrumentation channels and one of the four Engineered Safety Features Actuation (ESFAS) Instrumentation channels. DC electrical power subsystems 31 and 32 each support one of the two trains of RPS Instrumentation actuation logic and one of the two trains of ESFAS Instrumentation actuation logic.

BASES

BACKGROUND (Continued)

Electrical distribution, including DC Sources, is described in the FSAR (Ref. 4).

During normal operation, the 125 VDC load is powered from the battery chargers with the batteries floating on the system. In case of loss of normal power to the battery charger, the DC load is automatically powered from the station batteries.

Each of the four station batteries is sized to carry its expected shutdown loads for a period of 2 hours without battery terminal voltage falling below 105 volts following a plant trip that includes a loss of all AC power. Major loads with their approximate operating times on each battery are listed in Reference 4. The four battery chargers have been sized to recharge discharged batteries within 15 hours while carrying the normal DC subsystem load.

Battery 34 and charger 34 were installed in 1979 (along with inverter 34) to ensure a continuous power supply to 120 V AC vital instrument bus (VIB) 34 which supports RPS and ESFAS channel III. Prior to this modification, VIB 34 was powered solely by two 480 V/120 V constant voltage transformers (CVTs) supplied by separate safeguard power trains. Although these two CVTs provide redundant safety related power supplies for VIB 34, these power sources are unavailable following a loss of offsite power until the emergency diesel generators re-power one or both of the associated safeguards power trains. Additionally, battery 34 (via the associated inverter) provides a continuous power supply for VIB 34 which decreases the potential for an inadvertent reactor trip or ESFAS actuation, especially when an instrument channel associated with a different VIB is inoperable and in trip. Note that battery charger 34 is not required by LCO 3.8.4. This is acceptable because VIB 34 can be powered by either of the two CVTs supplied by separate safeguard power trains if battery charger 34 is not available following an event.

The DC power distribution system is described in more detail in Bases for LCO 3.8.9, "Distribution Systems – Operating," and LCO 3.8.10, "Distribution Systems – Shutdown."

BASES

BACKGROUND (Continued)

Each 125 VDC battery is separately housed in a ventilated room apart from its charger and power panels. Each subsystem is separated electrically from the other subsystems to ensure that a single failure in one subsystem does not cause a failure in a redundant subsystem. There is no sharing between redundant subsystems, such as batteries, battery chargers, or power panels.

The batteries are sized to produce required capacity at 80% of nameplate rating, corresponding to warranted capacity at end of life cycles and the 100% design demand. The voltage limit is 2.07 V per cell, which corresponds to a total minimum voltage output of ≥ 120.06 V for batteries 31 and 32 and ≥ 124.2 V for batteries 33 and 34.

Each DC electrical power subsystem has ample power output capacity for the steady state operation of connected loads required during normal operation, while at the same time maintaining its battery bank fully charged. Each battery charger also has sufficient capacity to restore the battery from the design minimum charge to the required charged state within 15 hours while supplying normal steady state loads discussed in the FSAR, Chapter 8 (Ref. 4).

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the FSAR, Chapter 14 (Ref. 6), assume that Engineered Safety Feature (ESF) systems are OPERABLE. The DC electrical power subsystems 31, 32 and 33 provide normal and emergency DC electrical power for the DGs, and control and switching during all MODES of operation. Each of the four DC electrical power subsystems supports one of the four 120 V AC vital instrument buses via an inverter.

The OPERABILITY of the DC sources is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This includes maintaining the DC sources OPERABLE during accident conditions in the event of:

BASES

APPLICABLE SAFETY ANALYSES (continued)

a. An assumed loss of all offsite AC power or all onsite AC power (i.e., emergency diesel generators); and

b. A worst case single failure.

The DC sources satisfy Criterion 3 of 10 CFR 50.36.

LCO

This LCO requires the OPERABILITY of the following four DC electrical power subsystems:

Battery 31 and associated Battery Charger;
Battery 32 and associated Battery Charger;
Battery 33 and associated Battery Charger; and
Battery 34.

In addition, the corresponding control equipment and interconnecting cabling supplying power to the associated bus within the train are required to be OPERABLE to ensure the availability of the required power to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence (AOO) or a postulated DBA. Loss of any train DC electrical power subsystem does not prevent the minimum safety function from being performed (Ref. 4).

An OPERABLE DC electrical power subsystem requires the battery and respective charger to be operating and connected to the associated DC bus.

APPLICABILITY

The DC electrical power sources are required to be OPERABLE in MODES 1, 2, 3, and 4 to ensure safe unit operation and to ensure that:

a. Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of AOOs or abnormal transients; and

BASES

APPLICABILITY (continued)

b. Adequate core cooling is provided, and containment integrity and other vital functions are maintained in the event of a postulated DBA.

The DC electrical power requirements for MODES 5 and 6 are addressed in the Bases for LCO 3.8.5, "DC Sources – Shutdown."

ACTIONS

A.1

Condition A is entered when battery No. 34 is not OPERABLE. The only safety related load supported by DC subsystem 34 is 120 V AC vital instrument bus 34 which is supplied via inverter 34. Therefore, the Required Actions for inverter 34 not OPERABLE specified in LCO 3.8.7, Inverters-Operating, are appropriate when battery No. 34 is not OPERABLE. Additionally, ITS 3.8.9 (and ITS Section 3.3) ensure that 120 V AC vital instrument bus 34 is energized when required. The 2 hour Completion Time is consistent with the completion time for an inoperable battery and/or charger in any of the other three DC electrical power subsystems.

B.1

Condition B is entered when DC subsystem 31, 32 or 33 (battery and/or associated charger) is not Operable. Loss of DC subsystem 34 (Condition A) differs from the loss of DC subsystem 31, 32 or 33 (Condition B) because Condition B could result in the loss of DC control power to 480 volt bus No. 5A, 6A, or 2A/3A, respectively, and the associated emergency diesel generator. Therefore, this Condition represents a significant degradation of the ability to completely respond to an event, and a potential loss of ability to remain energized during normal operation. It is, therefore, imperative that the operator's attention focus on stabilizing the unit, minimizing the potential loss of additional DC subsystems.

If one of the required DC electrical power subsystems is inoperable (e.g., inoperable battery, inoperable battery charger,

BASES

ACTIONS

B.1 (continued)

or inoperable battery charger and associated inoperable battery), the remaining DC electrical power subsystems have the capacity to support a safe shutdown and to mitigate an accident condition. Since a subsequent worst case single failure would, however, result in the loss of another 125 VDC electrical power subsystems with attendant loss of ESF functions, continued power operation should not exceed 2 hours. The 2 hour Completion Time is based on Regulatory Guide 1.93 (Ref. 7) and reflects a reasonable time to assess unit status as a function of the inoperable DC electrical power subsystem and, if the DC electrical power subsystem is not restored to OPERABLE status, to prepare to effect an orderly and safe unit shutdown.

C.1 and C.2

If the inoperable DC electrical power subsystem cannot be restored to OPERABLE status within the required Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging plant systems. The Completion Time to bring the unit to MODE 5 is consistent with the time required in Regulatory Guide 1.93 (Ref. 7).

SURVEILLANCE REQUIREMENTS

SR 3.8.4.1

Verifying battery terminal voltage while on float charge for the batteries helps to ensure the effectiveness of the charging system and the ability of the batteries to perform their intended function. Float charge is the condition in which the charger is supplying the continuous charge required to overcome the internal losses of a battery (or battery cell) and maintain the battery (or a battery cell) in a fully charged state. The voltage

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.1 (continued)

requirements are based on the nominal design voltage (i.e., 2.07 volts per cell) of the battery and are consistent with the initial voltages assumed in the battery sizing calculations. The 31 day Frequency is consistent with manufacturer recommendations and IEEE-450 (Ref.8).

SR 3.8.4.2

This SR requires that each battery charger be capable of supplying the voltage and current necessary to recharge partially discharged batteries (two hour discharge at a rate that does not cause battery terminal voltage to fall below 105 volts). These requirements are consistent with the output rating of the chargers (Ref. 4). Therefore, this SR can be satisfied by operating each charger at the design voltage and current for a minimum of 2 hours. According to Regulatory Guide 1.32 (Ref. 9), the battery charger supply is required to be based on the largest combined demands of the various steady state loads and the charging capacity to restore the battery from the design minimum charge state to the fully charged state, irrespective of the status of the unit during these demand occurrences. The minimum required amperes and duration ensures that these requirements can be satisfied.

The Surveillance Frequency is acceptable, given the unit conditions required to perform the test and the other administrative controls existing to ensure adequate charger performance during these 24 month intervals. In addition, this Frequency is intended to be consistent with expected fuel cycle lengths.

This Surveillance is required to be performed during MODES 5 and 6 since it would require the DC electrical power subsystem to be inoperable during performance of the test.

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would perturb the electrical distribution system and challenge safety systems.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.4.3

A battery service test is a special test of battery capability, as found, to satisfy the design requirements (battery duty cycle) of the DC electrical power system. The discharge rate and test length should correspond to the design duty cycle requirements as specified in Reference 4.

The Surveillance Frequency of 24 months is consistent with the recommendations of Regulatory Guide 1.32 (Ref. 9) and Regulatory Guide 1.129 (Ref. 10), which state that the battery service test should be performed during refueling operations or at some other outage.

A modified performance discharge test may be performed in lieu of a service test.

The modified performance discharge test is a simulated duty cycle consisting of just two rates; the one minute rate published for the battery or the largest current load of the duty cycle, followed by the test rate employed for the performance test, both of which envelope the duty cycle of the service test. Since the ampere-hours removed by a rated one minute discharge represents a very small portion of the battery capacity, the test rate can be changed to that for the performance test without compromising the results of the performance discharge test. The battery terminal voltage for the modified performance discharge test should remain above the minimum battery terminal voltage specified in the battery service test for the duration of time equal to that of the service test.

A modified performance discharge test is a test of the battery capacity and its ability to provide a high rate, short duration load (usually the highest rate of the duty cycle). This will often confirm the battery's ability to meet the critical period of the load duty cycle, in addition to determining its percentage of rated capacity. Initial conditions for the modified performance discharge test should be identical to those specified for a service test.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.3 (continued)

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would perturb the electrical distribution system and challenge safety systems.

SR 3.8.4.4

A battery performance discharge test is a test of constant current capacity of a battery, normally done in the as found condition, after having been in service, to detect any change in the capacity determined by the acceptance test. The test is intended to determine overall battery degradation due to age and usage.

A battery modified performance discharge test is described in the Bases for SR 3.8.4.3. Either the battery performance discharge test or the modified performance discharge test is acceptable for satisfying SR 3.8.4.4; however, only the modified performance discharge test may be used to satisfy SR 3.8.4.4 while satisfying the requirements of SR 3.8.4.3 at the same time.

The acceptance criteria for this Surveillance are consistent with IEEE-450 (Ref. 8) and IEEE-485 (Ref. 5). These references recommend that the battery be replaced if its capacity is below 80% of the manufacturer's rating. A capacity of 80% shows that the battery deterioration is increasing, even if there is ample capacity to meet the load requirements.

The Surveillance Frequency for this test is normally 60 months. If the battery shows degradation, or if the battery has reached 85% of its expected life and capacity is < 100% of the manufacturer's rating, the Surveillance Frequency is reduced to 12 months. However, if the battery shows no degradation but has reached 85% of its expected life, the Surveillance Frequency is only reduced to 24 months for batteries that retain capacity ≥ 100% of the manufacturer's rating. Degradation is indicated, according to IEEE-450 (Ref. 8), when the battery capacity drops by more than 10% relative to its capacity on the previous performance test or when it is ≥ 10% below the manufacturer's

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.4 (continued)

rating. These Frequencies are consistent with the recommendations in IEEE-450 (Ref. 8).

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would perturb the electrical distribution system and challenge safety systems.

REFERENCES

1. 10 CFR 50, Appendix A.
2. Regulatory Guide 1.6, March 10, 1971.
3. IEEE-308-1978.
4. FSAR, Chapter 8.
5. IEEE-485-1983, June 1983.
6. FSAR, Chapter 14.
7. Regulatory Guide 1.93, December 1974.
8. IEEE-450-1995.
9. Regulatory Guide 1.32, February 1977.
10. Regulatory Guide 1.129, December 1974.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.5 DC Sources – Shutdown

BASES

BACKGROUND

A description of the DC sources is provided in the Bases for LCO 3.8.4, "DC Sources – Operating."

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident and transient analyses in the FSAR, Chapter 14 (Ref. 1), assume that Engineered Safety Feature systems are OPERABLE. The DC electrical power system provides normal and emergency DC electrical power for the diesel generators and control and switching during all MODES of operation.

The OPERABILITY of the DC subsystems is consistent with the initial assumptions of the accident analyses and the requirements for the supported systems' OPERABILITY.

The OPERABILITY of the minimum DC electrical power sources during MODES 5 and 6 and during movement of irradiated fuel assemblies ensures that:

a. The unit can be maintained in the shutdown or refueling condition for extended periods;

b. Sufficient instrumentation and control capability is available for monitoring and maintaining the unit status; and

c. Adequate DC electrical power is provided to mitigate events postulated during shutdown, such as a fuel handling accident.

The DC sources satisfy Criterion 3 of 10 CFR 50.36.

BASES

LCO

The four DC electrical power subsystems, each subsystem consisting of one battery, one battery charger (except for battery charger 34 which is not covered by this LCO), and the corresponding control equipment and interconnecting cabling within the safeguards power train, are required to be OPERABLE to support required safeguards power trains of the distribution systems required OPERABLE by LCO 3.8.10, "Distribution Systems – Shutdown." This ensures the availability of sufficient DC electrical power sources to operate the unit in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents).

DC subsystems may be cross connected in Modes 5 and 6 and during movement of irradiated fuel because there is no requirement to ensure that a single failure in one subsystem does not cause a failure in a redundant subsystem.

APPLICABILITY

The DC electrical power sources required to be OPERABLE in MODES 5 and 6, and during movement of irradiated fuel assemblies, provide assurance that:

a. Required features to provide adequate coolant inventory makeup are available for the irradiated fuel assemblies in the core;

b. Required features needed to mitigate a fuel handling accident are available;

c. Required features necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition or refueling condition.

The DC electrical power requirements for MODES 1, 2, 3, and 4 are covered in LCO 3.8.4.

BASES

ACTIONS

A.1, A.2.1, A.2.2, A.2.3 and A.2.4

If any DC electrical subsystems are required by LCO 3.8.10 and one becomes inoperable, the remaining DC power available may be capable of supporting sufficient systems to allow continuation of CORE ALTERATIONS and fuel movement. By allowing the option to declare required features inoperable with the associated DC power source(s) inoperable, appropriate restrictions will be implemented in accordance with the affected required features LCO ACTIONS. In many instances, this option may involve undesired administrative efforts. Therefore, the allowance for sufficiently conservative actions is made (i.e., to suspend CORE ALTERATIONS, movement of irradiated fuel assemblies, and operations involving positive reactivity additions). The Required Action to suspend positive reactivity additions does not preclude actions to maintain or increase reactor vessel inventory, provided the required SDM is maintained.

Suspension of these activities shall not preclude completion of actions to establish a safe conservative condition. These actions minimize probability of the occurrence of postulated events. It is further required to immediately initiate action to restore the required DC electrical power subsystems and to continue this action until restoration is accomplished in order to provide the necessary DC electrical power to the unit safety systems.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required DC electrical power subsystems should be completed as quickly as possible in order to minimize the time during which the unit safety systems may be without sufficient power.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.5.1

SR 3.8.5.1 requires performance of all Surveillances required by SR 3.8.4.1 through SR 3.8.4.4. Therefore, see the corresponding Bases for LCO 3.8.4 for a discussion of each SR.

This SR is modified by a Note. The reason for the Note is to preclude requiring the OPERABLE DC sources from being discharged below their capability to provide the required power supply or otherwise rendered inoperable during the performance of SRs. It is the intent that these SRs must still be capable of being met, but actual performance is not required.

REFERENCES

1. FSAR, Chapter 14.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.6 Battery Cell Parameters

BASES

BACKGROUND

This LCO delineates the limits on electrolyte temperature, level, float voltage, and specific gravity for the DC power source batteries. A discussion of these batteries and their OPERABILITY requirements is provided in the Bases for LCO 3.8.4, "DC Sources - Operating," and LCO 3.8.5, "DC Sources - Shutdown."

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the FSAR, Chapter 14 (Ref. 1), assume Engineered Safety Feature systems are OPERABLE. The DC electrical power system provides normal and emergency DC electrical power for the diesel generators and control and switching during all MODES of operation.

The OPERABILITY of the DC subsystems is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This includes maintaining at least one train of DC sources OPERABLE during accident conditions, in the event of:

a. An assumed loss of all offsite AC power or all onsite AC power; and

b. A worst case single failure.

Battery cell parameters satisfy the Criterion 3 of 10 CFR 50.36.

LCO

Battery cell parameters must remain within acceptable limits to ensure availability of the required DC power to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence or a postulated DBA. Electrolyte limits

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BASES

LCO (continued)

are conservatively established, allowing continued DC electrical system function even with Category A and B limits not met.

APPLICABILITY

The battery cell parameters are required solely for the support of the associated DC electrical power subsystems. Therefore, battery electrolyte is only required when the DC power source is required to be OPERABLE. Refer to the Applicability discussion in Bases for LCO 3.8.4 and LCO 3.8.5.

ACTIONS

The ACTIONS Table is modified by a Note which indicates that separate Condition entry is allowed for each battery. This is acceptable because the Required Actions for each Condition provide appropriate compensatory actions for each inoperable DC subsystem. Complying with the Required Actions for one inoperable DC subsystem may allow for continued operation, and subsequent inoperable DC subsystem(s) are governed by separate Condition entry and application of associated Required Actions.

A.1, A.2 and A.3

With one or more cells in one or more batteries not within limits (i.e., Category A limits not met, Category B limits not met, or Category A and B limits not met) but within the Category C limits specified in Table 3.8.6-1 in the accompanying LCO, the battery is degraded but there is still sufficient capacity to perform the intended function. Therefore, the affected battery is not required to be considered inoperable solely as a result of Category A or B limits not met and operation is permitted for a limited period.

The pilot cell electrolyte level and float voltage are required to be verified to meet the Category C limits within 1 hour (Required Action A.1). This check will provide a quick indication of the status of the remainder of the battery cells. One hour provides time to inspect the electrolyte level and to confirm the float voltage of the pilot cells. One hour is

BASES

ACTIONS

A.1, A.2 and A.3 (continued)

considered a reasonable amount of time to perform the required verification.

Verification that the Category C limits are met (Required Action A.2) provides assurance that during the time needed to restore the parameters to the Category A and B limits, the battery is still capable of performing its intended function. A period of 24 hours is allowed to complete the initial verification because specific gravity measurements must be obtained for each connected cell. Taking into consideration both the time required to perform the required verification and the assurance that the battery cell parameters are not severely degraded, this time is considered reasonable. The verification is repeated at 7 day intervals until the parameters are restored to Category A or B limits. This periodic verification is more frequent than the normal Frequency of pilot cell Surveillances because of the degraded condition of the battery.

Continued operation is only permitted for 31 days before battery cell parameters must be restored to within Category A and B limits. With the consideration that, while battery capacity is degraded, sufficient capacity exists to perform the intended function and to allow time to fully restore the battery cell parameters to normal limits, this time is acceptable prior to declaring the battery inoperable.

B.1

With one or more batteries with one or more battery cell parameters outside the Category C limit for any connected cell, sufficient capacity to supply the maximum expected load requirement is not assured and the corresponding DC electrical power subsystem must be declared inoperable. Additionally, other potentially extreme conditions, such as not completing the Required Actions of Condition A within the required Completion Time or average electrolyte temperature of representative cells outside the limits of SR 3.8.6.3 are also cause for immediately declaring the associated DC electrical power subsystem inoperable.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.6.1

This SR verifies that Category A battery cell parameters are consistent with IEEE-450 (Ref. 2), which recommends regular battery inspections (at least one per month) including voltage, specific gravity, and electrolyte temperature of pilot cells.

SR 3.8.6.2

The quarterly inspection of specific gravity and voltage is consistent with IEEE-450 (Ref. 2) which recommends augmentation of the battery inspections conducted in SR 3.8.6.1 at least once per quarter by checking the level, voltage and specific gravity of each cell, and the temperature of pilot cells.

SR 3.8.6.3

This Surveillance verification that the average temperature of representative cells (i.e., every fifth cell) is within specified limits, is consistent with a recommendation of IEEE-450 (Ref. 2), that states that the temperature of electrolytes in representative cells should be determined on a quarterly basis.

Lower than normal temperatures act to inhibit or reduce battery capacity. This SR ensures that the operating temperatures remain within an acceptable operating range. This limit is based on manufacturer recommendations.

Table 3.8.6-1

This table delineates the limits on electrolyte level, float voltage, and specific gravity for three different categories. The meaning of each category is discussed below.

Category A defines the normal parameter limit for each designated pilot cell in each battery. The cells selected as pilot cells are those whose temperature, voltage, and electrolyte specific gravity approximate the state of charge of the entire battery.

BASES

SURVEILLANCE REQUIREMENTS

Table 3.8.6-1 (continued)

The Category A limits specified for electrolyte level are based on manufacturer recommendations and are consistent with the guidance in IEEE-450 (Ref. 2), with the extra ¼ inch allowance above the high water level indication for operating margin to account for temperatures and charge effects. In addition to this allowance, footnote a to Table 3.8.6-1 permits the electrolyte level to be above the specified maximum level during equalizing charge, provided it is not overflowing. These limits ensure that the plates suffer no physical damage, and that adequate electron transfer capability is maintained in the event of transient conditions. IEEE-450 (Ref. 2) recommends that electrolyte level readings should be made only after the battery has been at float charge for at least 72 hours.

The Category A limit specified for float voltage is ≥ 2.13 V per cell. This value is based on the recommendations of IEEE-450 (Ref. 2), which states that prolonged operation of cells < 2.13 V can reduce the life expectancy of cells.

The Category A limit specified for specific gravity for each pilot cell is ≥ 1.205 (0.010 below the manufacturer fully charged nominal specific gravity or a battery charging current that had stabilized at a low value). This value is characteristic of a charged cell with adequate capacity. According to IEEE-450 (Ref. 2), the specific gravity readings are based on a temperature of 77°F (25°C).

The specific gravity readings are corrected for actual electrolyte temperature as long as level is maintained within the required range. For each 3°F (1.67°C) above 77°F (25°C), 1 point (0.001) is added to the reading; 1 point is subtracted for each 3°F below 77°F. The specific gravity of the electrolyte in a cell increases with a loss of water due to electrolysis or evaporation.

BASES

SURVEILLANCE REQUIREMENTS

Table 3.8.6-1 (continued)

Category B defines the normal parameter limits for each connected cell. The term "connected cell" excludes any battery cell that may be jumpered out.

The Category B limits specified for electrolyte level and float voltage are the same as those specified for Category A and have been discussed above. The Category B limit specified for specific gravity for each connected cell is ≥ 1.195 (0.020 below the manufacturer fully charged, nominal specific gravity) with the average of all connected cells > 1.205 (0.010 below the manufacturer fully charged, nominal specific gravity). These values are based on manufacturer's recommendations. The minimum specific gravity value required for each cell ensures that the effects of a highly charged or newly installed cell will not mask overall degradation of the battery.

Category C defines the limits for each connected cell. These values, although reduced, provide assurance that sufficient capacity exists to perform the intended function and maintain a margin of safety. When any battery parameter is outside the Category C limits, the assurance of sufficient capacity described above no longer exists, and the battery must be declared inoperable.

The Category C limits specified for electrolyte level (above the top of the plates and not overflowing) ensure that the plates suffer no physical damage and maintain adequate electron transfer capability. The Category C limits for float voltage is based on IEEE-450 (Ref. 2), which states that a cell voltage of 2.07 V or below, under float conditions and not caused by elevated temperature of the cell, indicates internal cell problems and may require cell replacement.

The Category C limit of average specific gravity ≥ 1.195 is based on manufacturer recommendations (0.020 below the manufacturer recommended fully charged, nominal specific gravity). In addition to that limit, it is required that the specific gravity

BASES

SURVEILLANCE REQUIREMENTS

Table 3.8.6-1 (continued)

for each connected cell must be no less than 0.020 below the average of all connected cells. This limit ensures that the effect of a highly charged or new cell does not mask overall degradation of the battery.

REFERENCES

1. FSAR, Chapter 14.

2. IEEE-450-1995.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.7 Inverters – Operating

BASES

BACKGROUND

The inverters are the preferred source of power for the 120 V AC vital instrument buses because of the stability and reliability they achieve. The function of the inverter is to provide AC electrical power to the vital instrument buses.

There are four 120 volt AC vital instrument buses (VIBs), Nos. 31, 32, 33 and 34. The preferred power supplies to these buses are static inverters, Nos. 31, 32, 33 and 34, which are in turn supplied from separate 125 volt DC buses, Nos. 31, 32, 33 and 34. Each of the four 125 volt DC buses is powered by a battery and associated battery charger.

Inverters 31, 32, and 33 each have an associated backup 480 V/120 V constant voltage transformer (CVT). Each of these inverters has a manual bypass switch that causes the associated VIB to receive AC power from plant AC sources via the backup CVT instead of the DC powered inverter. Inverters 31, 32, and 33 will transfer to the backup power supply (i.e., the associated CVT) automatically in the event of an inverter failure. However, the backup CVTs for inverters 31, 32, and 33 are supplied from non-safety related buses that are stripped and not automatically re-connected following a safety injection (SI) signal or a loss of offsite power (LOOP). Therefore, operator action is required to re-energize VIBs 31, 32, or 33 following an SI or LOOP if the associated inverter is being bypassed or fails during the event. Additionally, the potential exists that the bus powering the backup CVT may not be available following an event.

Inverter 34 has two associated backup 480 V/120 V constant voltage transformers (CVTs). The CVTs associated with inverter 34 are powered from separate safeguards power trains using buses that are automatically re-energized following an SI or LOOP. Inverter 34 can be manually bypassed such that either of the associated CVTs can be used to power VIB 34. Inverter 34 will not automatically transfer to a backup power supply (i.e., the associated CVTs) in the event of an inverter failure. Manual

BASES

BACKGROUND (Continued)

operator action is also needed to transfer between the CVTs capable of powering VIB 34.

Using a separate battery and inverter to power each VIB ensures a continuous source of power for the instrumentation and controls of the engineered safety features (ESF) systems and the reactor protection system (RPS) during postulated events including the loss of offsite power. This is consistent with requirements described in Generic Letter 91-011 (Ref. 1). Continuity of power to the VIBs is assured because each of the four station batteries is sized to carry its expected shutdown loads for a period of 2 hours (Ref. 2). Additionally, four battery chargers have been sized to recharge these batteries while carrying the normal DC subsystem load (Ref. 2).

Note that battery charger 34 is not required by LCO 3.8.4. This is acceptable because VIB 34 can be powered by either of the two CVTs supplied by separate safeguard power trains if battery charger 34 is not available following an event. Specific details on inverters and their operating characteristics are found in the FSAR, Chapter 8 (Ref. 2).

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the FSAR, Chapter 14 (Ref. 3), assumes Engineered Safety Feature systems are OPERABLE. The inverters are designed to provide the required capacity, capability, redundancy, and reliability to ensure the availability of necessary power to the RPS and ESFAS instrumentation and controls so that the fuel, Reactor Coolant System, and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.4, Reactor Coolant System (RCS); and Section 3.6, Containment Systems.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The OPERABILITY of the inverters is consistent with the initial assumptions of the accident analyses and is based on meeting the design basis of the unit. This includes maintaining required 120 V AC vital instrument buses OPERABLE during accident conditions in the event of:

a. An assumed loss of all offsite AC electrical power or all onsite AC electrical power; and

b. A worst case single failure.

The 2 CVTs capable of supplying VIB 34 are needed to ensure the availability of power to VIB 34 following the depletion of battery 34. Although battery charger 34 would normally be used to supply VIB 34 via inverter 34, battery charger 34 is not safety related and may not be available after a design basis event.

Inverters are a part of the distribution system and, as such, satisfy Criterion 3 of 10 CFR 50.36.

LCO

The inverters (and CVTs associated with VIB 34) ensure the availability of AC electrical power for the systems instrumentation required to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence (AOO) or a postulated DBA.

Maintaining the required inverters (and CVTs associated with VIB 34) OPERABLE ensures that the redundancy incorporated into the design of the RPS and ESFAS instrumentation and controls is maintained. The four inverters ensure an uninterruptible supply of AC electrical power to the AC vital buses even if the 480 V safety buses are de-energized.

Operable inverters require the associated 120 V AC vital instrument bus to be powered by the inverter with output voltage and frequency within tolerances, and power input to the inverter from a 125 VDC station battery.

BASES

APPLICABILITY

The inverters are required to be OPERABLE in MODES 1, 2, 3, and 4 to ensure that:

a. Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of AOOs or abnormal transients; and

b. Adequate core cooling is provided, and containment OPERABILITY and other vital functions are maintained in the event of a postulated DBA.

Inverter requirements for MODES 5 and 6 are covered in the Bases for LCO 3.8.8, "Inverters – Shutdown."

ACTIONS

With an inverter inoperable, its associated VIB becomes inoperable until it is re-energized from its associated backup CVT. For this reason a Note to the Actions requires entry into the Conditions and Required Actions of LCO 3.8.9, "Distribution Systems - Operating." This ensures that the vital bus is re-energized within 2 hours.

A.1

With one of the two CVTs capable of supplying VIB 34 not OPERABLE, VIB 34 will be powered from battery 34 via inverter 34 for a minimum of 2 hours following the initiation of any event. After battery 34 is depleted, the second CVT capable of powering VIB 34 will maintain power to VIB 34 even if non-safety related battery charger 34 is not available. A 30 day Completion Time to restore both CVTs to OPERABLE is needed because a failure of the safeguards power train supporting the remaining CVT would result in the loss of two VIBs (i.e, VIB 34 and the VIB associated with the failed safeguards power train) but only after the associated batteries are depleted. A 30 day Completion Time to restore both CVTs to OPERABLE is acceptable because of the low probability of an accident in conjunction with the loss of a specific safeguards power train.

BASES

ACTIONS (continued)

B.1

With both of the CVTs capable of supplying VIB 34 not OPERABLE, VIB 34 will be powered from battery 34 via inverter 34 for a minimum of 2 hours following the initiation of any event. After battery 34 is depleted, inverter 34 may not be available to power VIB 34 because battery charger 34 is not safety related and is powered from a non-safety related bus. Therefore, at least one CVT must be restored within 7 days.

A 7 day Completion Time to restore at least one of the two CVTs to OPERABLE is needed and is acceptable because of the following: VIB 34 will be powered from battery 34 via inverter 34 for a minimum of 2 hours; non-safety related battery charger 34 may be available following an event; and, the low probability of an event during this 7 day period.

C.1 and C.2

With an inverter inoperable, its associated VIB must be powered from its associated backup CVT. However, the backup CVTs for inverters 31, 32, and 33 are supplied from non-safety related buses that are stripped and not automatically re-connected following a SI signal or a LOOP. Both backup CVTs for inverter 34 are powered from safety related buses that may be de-energized until the associated safeguards power train is energized (i.e., diesel generator starts). Therefore, a VIB powered from a backup CVT when the associated inverter is inoperable will be and could remain de-energized following a SI signal or a LOOP.

If a VIB will be de-energized as a result of SI signal or LOOP, a loss of safety function could exist for any VIB powered function that requires power to perform the required safety function (e.g., automatic actuation of core spray, Regulatory Guide 1.97 instrumentation, etc.) if the redundant required feature is inoperable. Therefore, Required Action C.1 requires declaring required feature(s) supported by associated inverter inoperable when its required redundant feature(s) is inoperable. As specified in the associated Note, this requirement only applies

BASES

ACTIONS

C.1 and C.2 (continued)

to feature(s) that require power to perform the required safety function. The 2 hour Completion Time is consistent with LCO 3.8.9, AC Distribution System - Operating, requirements for an inoperable VIB.

With an inverter inoperable and its associated VIB powered from its associated backup CVT, there is increased potential for inadvertent actuation for ESFAS or RPS functions, especially if redundant channels are inoperable and in the tripped condition. This is because these de-energize to actuate functions are relying upon interruptible AC electrical power sources (offsite and onsite). The uninterruptible inverter source to the VIBs is the preferred source for powering instrumentation trip setpoint devices. Therefore, only one inverter may be inoperable at one time and an inoperable inverter must be restored to OPERABLE within 7 days. The 7 day Completion Time is needed because it ensures that the VIBs are powered from the uninterruptible inverter source. The 7 day Completion Time is acceptable because Required Action C.1 ensures that an inoperable inverter does not result in a loss of any safety function. The 7 day Completion Time is consistent with commitments made in response to Generic Letter 91-011 (Ref. 1).

D.1 and D.2

If the inoperable devices or components cannot be restored to OPERABLE status within the required Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging plant systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.7.1

This Surveillance verifies that the inverters are functioning properly with all required circuit breakers closed and AC vital buses energized from the inverter. The verification of proper voltage output ensures that the required power is readily available for the instrumentation of the RPS and ESFAS connected to the AC vital buses. The 7 day Frequency takes into account the redundant capability of the inverters and other indications available in the control room that alert the operator to inverter malfunctions.

SR 3.8.7.2

This Surveillance verifies that the power supply to VIB 34 can be manually transferred from the inverter to each of the required CVTs. This SR ensures that power to VIB 34 can be maintained after the depletion of battery 34. The 24 month Frequency takes into account that either of the CVTs is capable of performing this safety function and the demonstrated reliability of this equipment.

REFERENCES

1. Generic Letter 91-011, Resolution of Generic Issues 48, "LCOs for Class 1E Vital Instrument Buses," and 49, "Interlocks and LCOS for Class 1E Tie Breakers" pursuant to 10 CFR 50.54(f).

2. FSAR, Chapter 8.

3. FSAR, Chapter 14.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.8 Inverters – Shutdown

BASES

BACKGROUND

A description of the inverters is provided in the Bases for LCO 3.8.7, "Inverters – Operating."

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the FSAR, Chapter 14 (Ref. 1), assume Engineered Safety Feature systems, including inverters that supply required 120 V AC vital instrument buses, are OPERABLE. The DC to AC inverters are designed to provide the required capacity, capability, redundancy, and reliability to ensure the availability of necessary power to the Reactor Protective System and Engineered Safety Features Actuation System instrumentation and controls so that the fuel, Reactor Coolant System, and containment design limits are not exceeded.

The OPERABILITY of the inverters is consistent with the initial assumptions of the accident analyses and the requirements for the supported systems' OPERABILITY.

The OPERABILITY of one inverter to each VIB bus during MODES 5 and 6 and when moving irradiated fuel ensures that:

a. The unit can be maintained in the shutdown or refueling condition for extended periods;

b. Sufficient instrumentation and control capability is available for monitoring and maintaining the unit status; and

c. Adequate power is available to mitigate events postulated during shutdown, such as a fuel handling accident.

The inverters were previously identified as part of the

BASES

APPLICABLE SAFETY ANALYSES (continued)

distribution system and, as such, satisfy Criterion 3 of 10 CFR 50.36.

LCO

The inverters ensure the availability of electrical power for the instrumentation for systems required to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence or a postulated DBA. The battery powered inverters provide uninterruptible supply of AC electrical power to the VIBs even if the 480 V safety buses are de-energized. OPERABILITY of the inverters requires that the VIB be powered by the inverter. This ensures the availability of sufficient inverter power sources to operate the unit in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents).

This LCO does not require OPERABILITY of the constant voltage transformers (CVTs) capable of supplying VIB 34 even if inverter 34 is required to be OPERABLE. This is acceptable because VIB 34 will be powered from battery 34 via inverter 34 for a minimum of 2 hours and electrical buses may be cross connected as needed to support inverter 34 prior to the depletion of battery 34.

APPLICABILITY

The inverters required to be OPERABLE in MODES 5 and 6 and during movement of irradiated fuel assemblies provide assurance that:

a. Systems to provide adequate coolant inventory makeup are available for the irradiated fuel in the core;

b. Systems needed to mitigate a fuel handling accident are available;

c. Systems necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

BASES

APPLICABILITY (continued)

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition or refueling condition.

Inverter requirements for MODES 1, 2, 3, and 4 are covered in LCO 3.8.7.

ACTIONS

A.1, A.2.1, A.2.2, A.2.3 and A.2.4

If more than one VIB is are required by LCO 3.8.10, "Distribution Systems – Shutdown," the remaining OPERABLE Inverters may be capable of supporting sufficient required features to allow continuation of CORE ALTERATIONS, fuel movement, and operations with a potential for positive reactivity additions. By the allowance of the option to declare required features inoperable with the associated inverter(s) inoperable, appropriate restrictions will be implemented in accordance with the affected required features LCOs' Required Actions. In many instances, this option may involve undesired administrative efforts. Therefore, the allowance for sufficiently conservative actions is made (i.e., to suspend CORE ALTERATIONS, movement of irradiated fuel assemblies, and operations involving positive reactivity additions). The Required Action to suspend positive reactivity additions does not preclude actions to maintain or increase reactor vessel inventory, provided the required SDM is maintained.

Suspension of these activities shall not preclude completion of actions to establish a safe conservative condition. These actions minimize the probability of the occurrence of postulated events. It is further required to immediately initiate action to restore the required inverters and to continue this action until restoration is accomplished in order to provide the necessary inverter power to the unit safety systems.

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required inverters should be completed as

BASES

ACTIONS

A.1, A.2.1, A.2.2, A.2.3 and A.2.4 (continued)

quickly as possible in order to minimize the time the unit safety systems may be without power or powered from a constant voltage source transformer.

SURVEILLANCE REQUIREMENTS

SR 3.8.8.1

This Surveillance verifies that the inverters are functioning properly with all required circuit breakers closed and VIBs energized from the inverter. The verification of proper voltage output ensures that the required power is readily available for the instrumentation connected to the VIBs. The 7 day Frequency takes into account the redundant capability of the inverters and other indications available in the control room that alert the operator to inverter malfunctions.

REFERENCES

1. FSAR, Chapter 14.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.9 Distribution Systems – Operating

BASES

BACKGROUND

The onsite AC, DC, and 120 V AC vital instrument bus VIB electrical power distribution systems are divided into three safeguards power trains (5A, 2A/3A and 6A) consisting of four 480 VAC safeguards buses and associated AC electrical power distribution subsystems, four 125 VDC bus subsystems, and four VIBs.

The safeguards subsystems are arranged in three trains such that any two trains are capable of meeting minimum requirements for accident mitigation or safe shutdown. The three safeguards subsystems consist of 480 volt bus 5A (associated with DG 33), 480 volt bus 6A (associated with DG 32), and 480 volt buses 2A and 3A (associated with DG 31). Buses 2A and 3A are considered a single safeguards bus. The electrical subsystems are identified in Table B 3.8.9-1.

The AC electrical power subsystem for each train consists of an Engineered Safety Feature (ESF) 480 V bus and motor control centers. Each 480 V bus has at least one offsite source of power as well as a dedicated onsite diesel generator (DG) source. Each of the four 480 V volt buses can receive offsite power from either the normal (138 kV) or alternate (13.8 kV) offsite source. The normal offsite power source uses either of the two 138 kilovolt (kV) ties from the Buchanan substation. The alternate offsite power source uses either of the two 13.8 kV ties from the Buchanan substation. There is no automatic transfer from the normal to the alternate source of offsite power.

Offsite power to 480 V buses 5A and 6A is supplied from 6.9 kV buses 5 and 6, respectively, which in turn receive power from either 138 kV offsite feeder via the Station Auxiliary Transformer (SAT). Alternately, 6.9 kV buses 5 and 6 can be supplied from either of the two 13.8 kV ties via an auto-transformer associated with the 13.8 kV feeder being used.

When the plant is at power, 480 V buses 2A and 3A are normally powered from the Main Generator via the Unit Auxiliary

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BASES

BACKGROUND (Continued)

Transformer (UAT) and the 6.9 kV buses 2 and 3 via SSTs 2 and 3. When the plant is not operating, buses 2A and 3A are supplied from 6.9 kV buses 5 and 6, respectively, via tie breakers. Following a unit trip, power to 480 V buses 2A and 3A is maintained by a fast transfer that connects buses 2A and 3A to power supplied from offsite to 6.9 kV buses 5 and 6. If the 138 kV system is not available, either of the two independent 13.8 kV feeders can be connected to the 6.9 kV buses through associated 20 MVA 13.8 KV/6.9 KV auto-transformers. When the 13.8 kV power source is used to feed 6.9 kV buses 5 and 6 and the main generator is used to feed 6.9 kV buses 1, 2, 3 and 4, automatic transfer of the 6.9 KV buses 1, 2, 3 and 4 to the 13.8 kV source following a unit trip must be prohibited to prevent overloading of the 13.8 kV auto-transformer. Therefore, a unit trip when a 13.8 kV power source is used to feed 6.9 kV buses 5 and 6 will result in 480 V busses 2A and 3A being de-energized and subsequently being powered from DG 31.

Each of the three 480 V safeguards subsystems receives DC control power from its associated battery charger and battery source. Battery No. 31 supplies DC control power to safeguards power train 5A including DG 33. Battery No. 32 supplies DC control power to safeguards power train 6A including DG 32. Battery No. 33 supplies DC control power to safeguards power train 2A/3A including DG 31. Batteries 31 and 32 also supply ESFAS and RPS trains A and B, respectively. Additional description of this system may be found in the Bases for LCO 3.8.1, "AC Sources - Operating," and the Bases for LCO 3.8.4, "DC Sources - Operating."

The AC electrical power distribution system for each train includes the safety related motor control centers shown in Table B 3.8.9-1.

The VIBs are arranged in four load groups and are normally powered from the inverters. There are four 120 volt vital AC instrument buses (VIBs). The four VIBs are powered by static inverters that are powered from the four separate 125 volt DC buses.

BASES

BACKGROUND (Continued)

Inverters 31, 32, and 33 each have an associated backup 480 V/120 V constant voltage transformer (CVT). Each of these inverters has a manual bypass switch that causes the associated VIB to receive AC power from plant AC sources via the backup CVT instead of the DC powered inverter. Inverters 31, 32, and 33 will transfer to the backup power supply (i.e., the associated CVT) automatically in the event of an inverter failure. However, the backup CVTs for inverters 31, 32, and 33 are supplied from non-safety related buses that are stripped and not automatically re-connected following a safety injection (SI) signal or a loss of offsite power (LOOP). Therefore, operator action is required to re-energize VIBs 31, 32, or 33 following an SI or LOOP if the associated inverter is being bypassed or fails during the event. Additionally, the potential exists that the bus powering the backup CVT may not be available following an event.

Inverter 34 has two associated backup 480 V/120 V constant voltage transformers (CVTs). The CVTs associated with inverter 34 are powered from separate safeguards power trains using buses that are automatically re-energized following an SI or LOOP. Inverter 34 can be manually bypassed such that either of the associated CVTs can be used to power VIB 34. Inverter 34 will not automatically transfer to a backup power supply (i.e., the associated CVTs) in the event of an inverter failure. Manual operator action is also needed to transfer between the CVTs capable of powering VIB 34.

The 125 volt DC system is divided into four buses with one battery and battery charger (supplied from the 480 volt system) serving each. The battery chargers supply the normal DC loads as well as maintaining proper charges on the batteries. The DC system is redundant from battery source to actuation devices which are powered from the batteries. Four batteries feed four DC power panels, which in turn feed major loads, such as instrument bus inverters and switchgear control circuits. DC power panels 31 and 32 feed DC distribution panels, which in turn feed relaying and instrumentation loads. Continuity of power to

BASES

BACKGROUND (Continued)

the VIBs is assured because each of the four station batteries is sized to carry its expected shutdown loads for a period of 2 hours. Additionally, four battery chargers have been sized to recharge these batteries while carrying the normal DC subsystem load (Ref. 2).

Note that battery charger 34 is not required by LCO 3.8.4, DC Sources - Operating. This is acceptable because VIB 34 can be powered by either of the two CVTs supplied by separate safeguard power trains if battery charger 34 is not available following an event. The 2 CVTs capable of supplying VIB 34 are needed to ensure the availability of power to VIB 34 following the depletion of battery 34. Although battery charger 34 would normally be used to supply VIB 34 via inverter 34, battery charger 34 is not safety related and may not be available after a design basis event.

The list of all required distribution buses is presented in Table B 3.8.9-1.

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the FSAR, Chapter 14 (Ref. 1), assume ESF systems are OPERABLE. The AC, DC, and AC vital instrument bus electrical power distribution systems are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System, and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.4, Reactor Coolant System (RCS); and Section 3.6, Containment Systems.

The OPERABILITY of the AC, DC, and VIB electrical power distribution systems is consistent with the initial assumptions of the accident analyses and is based upon meeting the design

BASES

APPLICABLE SAFETY ANALYSES (continued)

basis of the unit. This includes maintaining power distribution systems OPERABLE during accident conditions in the event of:

a. An assumed loss of all offsite power or all onsite AC electrical power; and

b. A worst case single failure.

The distribution systems satisfy Criterion 3 of 10 CFR 50.36.

LCO

The required power distribution subsystems listed in Table B 3.8.9-1 ensure the availability of AC, DC, and VIB electrical power for the systems required to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence (AOO) or a postulated DBA. The AC, DC, and VIB electrical power distribution subsystems are required to be OPERABLE.

Maintaining the AC, DC, and VIB electrical power distribution subsystems OPERABLE ensures that the redundancy incorporated into the design of ESF is not defeated. Therefore, a single failure within any system or within the electrical power distribution subsystems will not prevent safe shutdown of the reactor.

OPERABLE AC electrical power distribution subsystems require the associated buses and safety related motor control centers to be energized to their proper voltages. OPERABLE DC electrical power distribution subsystems require the associated buses to be energized to their proper voltage from either the associated battery or charger. OPERABLE vital instrument bus electrical power distribution subsystems require the associated buses to be energized to their proper voltage from the associated inverter via inverted DC voltage or constant voltage transformer.

In addition, tie breakers between redundant safety related AC, DC, and VIB power distribution subsystems must be open. This prevents any electrical malfunction in any power distribution subsystem from propagating to the redundant subsystem, that could

BASES

LCO (continued)

cause the failure of a redundant subsystem and a loss of essential safety function(s). If any tie breakers are closed, the affected redundant electrical power distribution subsystems are considered inoperable. This applies to the onsite, safety related redundant electrical power distribution subsystems. It does not, however, preclude redundant 480 V buses from being powered from the same offsite circuit.

APPLICABILITY

The electrical power distribution subsystems are required to be OPERABLE in MODES 1, 2, 3, and 4 to ensure that:

a. Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of AOOs or abnormal transients; and

b. Adequate core cooling is provided, and containment OPERABILITY and other vital functions are maintained in the event of a postulated DBA.

Electrical power distribution subsystem requirements for MODES 5 and 6 are covered in the Bases for LCO 3.8.10, "Distribution Systems – Shutdown."

ACTIONS

A.1

With one or more required AC buses or motor control centers (except VIBs) in one train inoperable, the remaining AC electrical power distribution subsystems in the other trains are capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming no single failure and that redundant required features are OPERABLE. The overall reliability is reduced, however, because a single failure in the remaining power distribution subsystems could result in the minimum required ESF functions not being supported. Therefore, the required AC buses

BASES

ACTIONS

A.1 (continued)

and motor control centers must be restored to OPERABLE status within 8 hours.

Condition A worst scenario is one train without AC power (i.e., no offsite power to the train and the associated DG inoperable). In this Condition, the unit is more vulnerable to a loss of the minimum required AC power. It is, therefore, imperative that the unit operator's attention be focused on minimizing the potential for loss of power to the remaining trains by stabilizing the unit, and on restoring power to the affected train. The 8 hour time limit before requiring a unit shutdown in this Condition is acceptable because of:

a. The potential for decreased safety if the unit operator's attention is diverted from the evaluations and actions necessary to restore power to the affected train, to the actions associated with taking the unit to shutdown within this time limit; and

b. The potential for an event in conjunction with a single failure of a redundant component in the train with AC power.

The second Completion Time for Required Action A.1 establishes a limit on the maximum time allowed for any combination of required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition A is entered while, for instance, a DC bus is inoperable and subsequently restored OPERABLE, the LCO may already have been not met for up to 2 hours. This could lead to a total of 10 hours, since initial failure of the LCO, to restore the AC distribution system. At this time, a DC circuit could again become inoperable, and AC distribution restored OPERABLE. This could continue indefinitely.

The Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This will result in establishing the "time zero" at the time the LCO was initially not met, instead of the time Condition A was entered. The 16 hour Completion Time is an acceptable

BASES

ACTIONS

A.1 (continued)

limitation on this potential to fail to meet the LCO indefinitely.

B.1

With one VIB inoperable, the remaining OPERABLE AC vital inststrument buses are capable of supporting the minimum safety functions necessary to shut down the unit and maintain it in the safe shutdown condition assuming redundant required features are inoperable. Overall reliability is reduced, however, since an additional single failure could result in the minimum required ESF functions not being supported. Therefore, the required AC vital instrument bus must be restored to OPERABLE status within 2 hours by powering the bus from the associated inverter via inverted DC, or constant voltage transformer.

Condition B represents one VIB without power; potentially both the DC source and the associated AC source are nonfunctioning. In this situation, the unit is significantly more vulnerable to a complete loss of minimum required noninterruptible power. It is, therefore, imperative that the operator's attention focus on stabilizing the unit, minimizing the potential for loss of power to the remaining vital instrument buses and restoring power to the affected vital instrument bus.

This 2 hour limit is more conservative than Completion Times allowed for the vast majority of components that are without adequate vital instrument bus AC power. Taking exception to LCO 3.0.2 for components without adequate vital instrument bus AC power, that would have the Required Action Completion Times shorter than 2 hours if declared inoperable, is acceptable because of:

a. The potential for decreased safety by requiring a change in unit conditions (i.e., requiring a shutdown) and not allowing stable operations to continue;

BASES

ACTIONS

B.1 (continued)

b. The potential for decreased safety by requiring entry into numerous Applicable Conditions and Required Actions for components without adequate VIB AC power and not providing sufficient time for the operators to perform the necessary evaluations and actions for restoring power to the affected train; and

c. The potential for an event in conjunction with a single failure of a redundant component.

The 2 hour Completion Time takes into account the importance to safety of restoring the VIB to OPERABLE status, the redundant capability afforded by the other OPERABLE vital buses, and the low probability of a DBA occurring during this period.

The second Completion Time for Required Action B.1 establishes a limit on the maximum allowed for any combination of required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition B is entered while, for instance, an AC bus is inoperable and subsequently returned OPERABLE, the LCO may already have been not met for up to 8 hours. This could lead to a total of 10 hours, since initial failure of the LCO, to restore the VIB distribution system. At this time, an AC train could again become inoperable, and VIB distribution restored OPERABLE. This could continue indefinitely.

This Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This will result in establishing the "time zero" at the time the LCO was initially not met, instead of the time Condition B was entered. The 16 hour Completion Time is an acceptable limitation on this potential to fail to meet the LCO indefinitely.

C.1

With one DC bus inoperable, the remaining DC electrical power distribution subsystems are capable of supporting the minimum safety functions necessary to shut down the reactor and maintain

BASES

ACTIONS

C.1 (continued)

it in a safe shutdown condition, assuming no single failure and that redundant required features are OPERABLE. The overall reliability is reduced, however, because a single failure in the remaining DC electrical power distribution subsystems could result in the minimum required ESF functions not being supported. Therefore, the required DC buses must be restored to OPERABLE status within 2 hours by powering the bus from the associated battery or charger.

Condition C represents one train without adequate DC power; potentially both with the battery significantly degraded and the associated charger nonfunctioning. In this situation, the unit is significantly more vulnerable to a loss of minimum required DC power. It is, therefore, imperative that the operator's attention focus on stabilizing the unit, minimizing the potential for loss of power to the remaining trains and restoring power to the affected train.

This 2 hour limit is more conservative than Completion Times allowed for the vast majority of components that would be without power. Taking exception to LCO 3.0.2 for components without adequate DC power, which would have Required Action Completion Times shorter than 2 hours, is acceptable because of:

a. The potential for decreased safety by requiring a change in unit conditions (i.e., requiring a shutdown) while allowing stable operations to continue;

b. The potential for decreased safety by requiring entry into numerous applicable Conditions and Required Actions for components without DC power and not providing sufficient time for the operators to perform the necessary evaluations and actions for restoring power to the affected train; and

c. The potential for an event in conjunction with a single failure of a redundant component.

The 2 hour Completion Time for DC buses is consistent with Regulatory Guide 1.93 (Ref. 2). The second Completion Time for

BASES

ACTIONS

C.1 (continued)

Required Action C.1 establishes a limit on the maximum time allowed for any combination of required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition C is entered while, for instance, an AC bus is inoperable and subsequently returned OPERABLE, the LCO may already have been not met for up to 8 hours. This could lead to a total of 10 hours, since initial failure of the LCO, to restore the DC distribution system. At this time, an AC train could again become inoperable, and DC distribution restored OPERABLE. This could continue indefinitely.

This Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This will result in establishing the "time zero" at the time the LCO was initially not met, instead of the time Condition C was entered. The 16 hour Completion Time is an acceptable limitation on this potential to fail to meet the LCO indefinitely.

D.1 and D.2

If the inoperable distribution subsystem cannot be restored to OPERABLE status within the required Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging plant systems.

E.1

With one or more trains with inoperable distribution subsystems that result in a loss of safety function, adequate core cooling, containment OPERABILITY and other vital functions for DBA mitigation would be compromised, and immediate plant shutdown in accordance with LCO 3.0.3 is required.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.9.1

This Surveillance verifies that the AC, DC, and AC vital instrument bus electrical power distribution systems are functioning properly, with the correct circuit breaker alignment. The correct breaker alignment ensures the appropriate separation and independence of the electrical divisions is maintained, and the appropriate voltage is available to each required bus. The verification of proper voltage availability on the buses ensures that the required voltage is readily available for motive as well as control functions for critical system loads connected to these buses. The 7 day Frequency takes into account the redundant capability of the AC, DC, and AC vital instrument bus electrical power distribution subsystems, and other indications available in the control room that alert the operator to subsystem malfunctions.

REFERENCES

1. FSAR, Chapter 14.
2. Regulatory Guide 1.93, December 1974.

Table B 3.8.9-1 (page 1 of 1)
AC and DC Electrical Power Distribution Systems

TYPE	VOLTAGE	Safeguards Power Train 5A (DG 33)	Safeguards Power Train 2A/3A (DG 31)	Safeguards Power Train 6A (DG 32)	
AC Electrical Power Distribution subsystems	480 V	bus 5A[1] MCC 36A MCC 36E	bus 2A[1] bus 3A[1] MCC 36C	bus 6A[1] MCC 36B MCC 36D	
AC vital instrument buses (VIBs)	120 V	bus 31 bus 31A	bus 33 bus 33A	bus 32 bus 32A	bus 34[3] bus 34A[3]
DC buses	125 V	bus 31[2]	bus 33[2]	bus 32[2]	bus 32[2]

(1) Tie breakers must be open between buses 5A and 2A and between buses 3A and 6A.

(2) Tie breakers between DC buses must be open.

(3) The AC Power supply to the VIB 34 and VIB 34A is supplied from MCC 36B or MCC 36C as described in the Bases for LCO 3.8.7, Inverters - Operating.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.10 Distribution Systems – Shutdown

BASES

BACKGROUND

A description of the AC, DC, and 120 V AC vital instrument bus (VIB) electrical power distribution systems is provided in the Bases for LCO 3.8.9, "Distribution Systems – Operating."

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident and transient analyses in the FSAR, Chapter 14 (Ref. 1), assumes Engineered Safety Feature (ESF) systems are OPERABLE. The AC, DC, and VIB electrical power distribution systems are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System, and containment design limits are not exceeded.

The OPERABILITY of the AC, DC, and VIB electrical power distribution system is consistent with the initial assumptions of the accident analyses and the requirements for the supported systems' OPERABILITY.

The OPERABILITY of the minimum AC, DC, and VIB electrical power distribution subsystems during MODES 5 and 6, and during movement of irradiated fuel assemblies ensures that:

a. The unit can be maintained in the shutdown or refueling condition for extended periods;

b. Sufficient instrumentation and control capability is available for monitoring and maintaining the unit status; and

c. Adequate power is provided to mitigate events postulated during shutdown, such as a fuel handling accident.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The AC and DC electrical power distribution systems satisfy Criterion 3 of 10 CFR 50.36.

LCO

Various combinations of subsystems, equipment, and components are required OPERABLE by other LCOs, depending on the specific plant condition. Implicit in those requirements is the required OPERABILITY of necessary support required features. This LCO explicitly requires energization of the portions of the electrical distribution system necessary to support OPERABILITY of required systems, equipment, and components – all specifically addressed in each LCO and implicitly required via the definition of OPERABILITY.

Maintaining these portions of the distribution system energized ensures the availability of sufficient power to operate the unit in a safe manner to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents).

APPLICABILITY

The AC and DC electrical power distribution subsystems required to be OPERABLE in MODES 5 and 6, and during movement of irradiated fuel assemblies, provide assurance that:

a. Systems to provide adequate coolant inventory makeup are available for the irradiated fuel in the core;

b. Systems needed to mitigate a fuel handling accident are available;

c. Systems necessary to mitigate the effects of events that can lead to core damage during shutdown are available; and

d. Instrumentation and control capability is available for monitoring and maintaining the unit in a cold shutdown condition and refueling condition.

BASES

APPLICABILITY (continued)

The AC, DC, and VIB electrical power distribution subsystems requirements for MODES 1, 2, 3, and 4 are covered in LCO 3.8.9.

ACTIONS

A.1, A.2.1, A.2.2, A.2.3, A.2.4 and A.2.5

Although redundant required features may require redundant trains of electrical power distribution subsystems to be OPERABLE, one OPERABLE distribution subsystem train may be capable of supporting sufficient required features to allow continuation of CORE ALTERATIONS and fuel movement. By allowing the option to declare required features associated with an inoperable distribution subsystem inoperable, appropriate restrictions are implemented in accordance with the affected distribution subsystem LCO's Required Actions. In many instances, this option may involve undesired administrative efforts. Therefore, the allowance for sufficiently conservative actions is made (i.e., to suspend CORE ALTERATIONS, movement of irradiated fuel assemblies, and operations involving positive reactivity additions).

Suspension of these activities does not preclude completion of actions to establish a safe conservative condition. These actions minimize the probability of the occurrence of postulated events. It is further required to immediately initiate action to restore the required AC and DC electrical power distribution subsystems and to continue this action until restoration is accomplished in order to provide the necessary power to the unit safety systems.

Notwithstanding performance of the above conservative Required Actions, a required residual heat removal (RHR) subsystem may be inoperable. In this case, Required Actions A.2.1 through A.2.4 do not adequately address the concerns relating to coolant circulation and heat removal. Pursuant to LCO 3.0.6, the RHR ACTIONS would not be entered. Therefore, Required Action A.2.5 is provided to direct declaring RHR inoperable, which results in taking the appropriate RHR actions.

BASES

ACTIONS

A.1, A.2.1, A.2.2, A.2.3, A.2.4 and A.2.5 (continued)

The Completion Time of immediately is consistent with the required times for actions requiring prompt attention. The restoration of the required distribution subsystems should be completed as quickly as possible in order to minimize the time the unit safety systems may be without power.

SURVEILLANCE REQUIREMENTS

SR 3.8.10.1

This Surveillance verifies that the AC, DC, and VIB electrical power distribution subsystems are functioning properly, with all the buses energized. The verification of proper voltage availability on the buses ensures that the required power is readily available for motive as well as control functions for critical system loads connected to these buses. The 7 day Frequency takes into account the capability of the electrical power distribution subsystems, and other indications available in the control room that alert the operator to subsystem malfunctions.

REFERENCES

1. FSAR, Chapter 14.

B 3.9 REFUELING OPERATIONS

B 3.9.1 Boron Concentration

BASES

BACKGROUND

The limit on the boron concentrations of the Reactor Coolant System (RCS) and the refueling cavity (which includes the refueling canal) during refueling ensures that the reactor remains subcritical during MODE 6. Refueling boron concentration is the soluble boron concentration in the coolant in each of these volumes having direct access to the reactor core during refueling.

The soluble boron concentration offsets the core reactivity and is measured by chemical analysis of a representative sample of the coolant in each of the volumes. The refueling boron concentration limit is specified in the COLR. Plant procedures ensure the specified boron concentration in order to maintain an overall core reactivity of $k_{eff} \leq 0.95$ during fuel handling, with control rods and fuel assemblies assumed to be in the most adverse configuration (least negative reactivity) allowed by plant procedures.

GDC 26 of 10 CFR 50, Appendix A, requires that two independent reactivity control systems of different design principles be provided (Ref. 1). One of these systems must be capable of holding the reactor core subcritical under cold conditions. The Chemical and Volume Control System (CVCS) is the system capable of maintaining the reactor subcritical in cold conditions by maintaining the boron concentration.

The reactor is brought to shutdown conditions before beginning operations to open the reactor vessel for refueling. After the RCS is cooled and depressurized and the vessel head is unbolted, the head is slowly removed to form the refueling cavity. The refueling canal and the refueling cavity are then flooded with borated water from the refueling water storage tank.

The pumping action of the RHR System in the RCS and the natural circulation due to thermal driving heads in the reactor vessel and refueling cavity mix the added concentrated boric acid with the water in the refueling canal. The RHR System is in operation

BASES

BACKGROUND (Continued)

during refueling (see LCO 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation—High Water Level," and LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation—Low Water Level") to provide forced circulation in the RCS and assist in maintaining the boron concentrations in the RCS and the refueling cavity above the COLR limit.

APPLICABLE SAFETY ANALYSES

During refueling operations, the reactivity condition of the core is consistent with the initial conditions assumed for the boron dilution accident in the accident analysis and is conservative for MODE 6. The boron concentration limit specified in the COLR is based on the core reactivity at the beginning of each fuel cycle (the end of refueling) and includes an uncertainty allowance.

The required boron concentration and the plant refueling procedures that verify the correct fuel loading plan (including full core mapping) ensure that the k_{eff} of the core will remain ≤ 0.95 during the refueling operation. Hence, at least a 5% $\Delta k/k$ margin of safety is established during refueling.

During refueling, the water volume in the spent fuel pit, the transfer canal, the refueling canal, the refueling cavity, and the reactor vessel form a single mass. As a result, the soluble boron concentration is relatively the same in each of these volumes.

The limiting boron dilution accident analyzed occurs in MODE 5 (Ref. 2). A detailed discussion of this event is provided in Bases for LCO 3.1.1, "SHUTDOWN MARGIN (SDM)."

The RCS boron concentration satisfies Criterion 2 of 10 CFR 50.36.

BASES

LCO

The LCO requires that a minimum boron concentration be maintained in all filled portions of the RCS and the refueling cavity (which includes the refueling canal) while in MODE 6. The boron concentration limit specified in the COLR ensures that a core k_{eff} of ≤ 0.95 is maintained during fuel handling operations. Violation of the LCO could lead to an inadvertent criticality during MODE 6.

APPLICABILITY

This LCO is applicable in MODE 6 to ensure that the fuel in the reactor vessel will remain subcritical. The required boron concentration ensures a $k_{eff} \leq 0.95$. Above MODE 6, LCO 3.1.1, "SHUTDOWN MARGIN (SDM)" ensures that an adequate amount of negative reactivity is available to shut down the reactor and maintain it subcritical.

ACTIONS

A.1 and A.2

Continuation of CORE ALTERATIONS or positive reactivity additions (including actions to reduce boron concentration) is contingent upon maintaining the unit in compliance with the LCO. If the boron concentration of any coolant volume in the RCS or the refueling cavity is less than its limit, all operations involving CORE ALTERATIONS or positive reactivity additions must be suspended immediately.

Suspension of CORE ALTERATIONS and positive reactivity additions shall not preclude moving a component to a safe position.

A.3

In addition to immediately suspending CORE ALTERATIONS or positive reactivity additions, boration to restore the concentration must be initiated immediately.

In determining the required combination of boration flow rate and concentration, no unique Design Basis Event must be satisfied. The only requirement is to restore the boron concentration to its required value as soon as possible. In order to raise the boron

BASES

ACTIONS

A.3 (continued)

concentration as soon as possible, the operator should begin boration with the best source available for unit conditions.

Once actions have been initiated, they must be continued until the boron concentration is restored. The restoration time depends on the amount of boron that must be injected to reach the required concentration.

SURVEILLANCE REQUIREMENTS

SR 3.9.1.1

This SR ensures that the coolant boron concentration in the RCS and the refueling cavity is within the COLR limits. For sampling purposes, the refueling cavity and canal are considered a single volume. The boron concentration of the coolant in each volume is determined periodically by chemical analysis.

A minimum Frequency of once every 72 hours is a reasonable amount of time to verify the boron concentration of representative samples. The Frequency is based on operating experience, which has shown 72 hours to be adequate.

REFERENCES

1. 10 CFR 50, Appendix A.

2. FSAR, Chapter 14.

B 3.9 REFUELING OPERATIONS

B 3.9.2 Nuclear Instrumentation

BASES

BACKGROUND

The source range neutron flux monitors are used during refueling operations to monitor the core reactivity condition. Two installed source range neutron flux monitors (N-31 and N-32) are part of the Nuclear Instrumentation System (NIS). Additionally, the full range Excore Neutron Flux Detection System, which was installed to satisfy Regulatory Guide 1.97 requirements, includes two channels (N-38 and N-39) capable of monitoring the source range. The full range Excore Neutron Flux Detection System provides indication of subcritical neutron flux in the Control Room using the Qualified Safety Parameters Display System (QSPDS). These detectors are located external to the reactor vessel and detect neutrons leaking from the core.

The NIS installed source range neutron flux monitors are BF3 detectors operating in the proportional region of the gas filled detector characteristic curve. The detectors monitor the neutron flux in counts per second. The two source range NIS detectors sense thermal neutrons in the range from 1×10^{-1} to 5×10^{4} neutrons per square cm per second. In addition to count rate indication in the Control Room, this instrumentation annunciates a local horn and an alarm and light in the Control Room if the count rate increases above a preset level.

The full range Excore Neutron Flux Detection System uses high-sensitivity fission chambers sensing thermal neutrons in the range from 10^{-2} to 10^{10} neutrons per square cm per second. In addition to count rate indication from the QSPDS, this instrumentation is capable of supplying audible indication of the count rate in the control room.

The core subcritical neutron flux is continuously monitored by two source range neutron monitors which provide warning of any approach to criticality during refueling operations to alert operators to a potential boron dilution event. The operators are alerted to significant changes in the subcritical neutron flux by either the alarm or by monitoring the audible neutron count rate.

BASES

APPLICABLE SAFETY ANALYSES

Two OPERABLE source range neutron flux monitors are required to provide a signal to alert the operator to unexpected changes in core reactivity such as with a boron dilution accident (Ref. 2) or an improperly loaded fuel assembly. The audible count rate from a source range neutron flux monitor provides prompt and definite indication of any boron dilution. The count rate increase is proportional to the subcritical multiplication factor and allows operators to promptly recognize the initiation of a boron dilution event. Prompt recognition of the initiation of a boron dilution event is consistent with the assumptions of the safety analysis and is necessary to assure sufficient time is available for isolation of the primary water makeup source before SHUTDOWN MARGIN is lost (Ref. 2).

The source range neutron flux monitors satisfy Criterion 3 of 10 CFR 50.36.

LCO

This LCO requires that two source range neutron flux monitors be OPERABLE to ensure that redundant monitoring capability is available to detect changes in core reactivity. To be OPERABLE, each source range monitor must provide visual indication in the Control Room. In addition, each source range channel must provide either an alarm at a preset neutron flux level or continuous audible signal in the Control Room.

APPLICABILITY

In MODE 6, the source range neutron flux monitors must be OPERABLE to determine changes in core reactivity. There are no other direct means available to check core reactivity levels. In MODES 2, 3, 4, and 5, these same installed source range detectors and circuitry may also be required to be OPERABLE by LCO 3.3.1, "Reactor Trip System (RTS) Instrumentation."

BASES

ACTIONS

A.1 and A.2

With only one source range neutron flux monitor OPERABLE, redundancy has been lost. Since these instruments are the only direct means of monitoring core reactivity conditions, CORE ALTERATIONS and positive reactivity additions must be suspended immediately. Performance of Required Action A.1 shall not preclude completion of movement of a component to a safe position.

B.1

With no source range neutron flux monitor OPERABLE, action to restore a monitor to OPERABLE status shall be initiated immediately. Once initiated, action shall be continued until a source range neutron flux monitor is restored to OPERABLE status.

B.2

With no source range neutron flux monitor OPERABLE, there are no direct means of detecting changes in core reactivity. However, since CORE ALTERATIONS and positive reactivity additions are not to be made, the core reactivity condition is stabilized until the source range neutron flux monitors are OPERABLE. This stabilized condition is determined by performing SR 3.9.1.1 to ensure that the required boron concentration exists.

The Completion Time of once per 12 hours is sufficient to obtain and analyze a reactor coolant sample for boron concentration and ensures that unplanned changes in boron concentration would be identified. The 12 hour Frequency is reasonable, considering the low probability of a change in core reactivity during this time period.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.9.2.1

SR 3.9.2.1 is the performance of a CHANNEL CHECK, which is a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that the two indication channels should be consistent with core conditions. Changes in fuel loading and core geometry can result in significant differences between source range channels, but each channel should be consistent with its local conditions.

The Frequency of 12 hours is consistent with the CHANNEL CHECK Frequency specified similarly for the same instruments in LCO 3.3.1.

SR 3.9.2.2

SR 3.9.2.2 is the performance of a CHANNEL CALIBRATION every 24 months. This SR is modified by a Note stating that neutron detectors are excluded from the CHANNEL CALIBRATION. The CHANNEL CALIBRATION for the source range neutron flux monitors consists of obtaining the detector plateau or preamp discriminator curves, evaluating those curves, and comparing the curves to the manufacturer's data. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage. Operating experience has shown these components usually pass the Surveillance when performed at the 24 month Frequency.

REFERENCES

1. 10 CFR 50, Appendix A.

2. FSAR, Section 14.1.

B 3.9 REFUELING OPERATIONS

B 3.9.3 Containment Penetrations

BASES

BACKGROUND

During CORE ALTERATIONS or movement of irradiated fuel assemblies within containment, a release of fission product radioactivity within containment will be restricted from escaping to the environment when the LCO requirements are met. In MODES 1, 2, 3, and 4, this is accomplished by maintaining containment OPERABLE as described in LCO 3.6.1, "Containment." In MODE 6, the potential for containment pressurization as a result of an accident is not likely; therefore, requirements to isolate the containment from the outside atmosphere can be less stringent. The LCO requirements are referred to as "containment closure" rather than "containment OPERABILITY." Containment closure means that all potential escape paths are closed, except for the OPERABLE Purge System Penetration. Since there is no potential for containment pressurization, the Appendix J leakage criteria and tests are not required.

The containment serves to contain fission product radioactivity that may be released from the reactor core following an accident, such that offsite radiation exposures are maintained well within the requirements of 10 CFR 100. Additionally, the containment provides radiation shielding from the fission products that may be present in the containment atmosphere following accident conditions.

The containment equipment hatch, which is part of the containment pressure boundary, provides a means for moving large equipment and components into and out of containment. During CORE ALTERATIONS or movement of irradiated fuel assemblies within containment, the equipment hatch must be held in place by at least four bolts. Good engineering practice dictates that the bolts required by this LCO be approximately equally spaced.

In lieu of maintaining the equipment hatch in place for containment closure, a temporary closure device may be used to maintain containment closure during core alterations or during movement of irradiated fuel assemblies within containment. The

BASES

BACKGROUND (Continued)

temporary closure device may provide penetrations for temporary services or personnel access. The temporary closure device will be designed to withstand a seismic event and designed to a withstand a pressure which ensures containment closure during refueling operations. The closure device will provide the same level of protection as that of the equipment hatch for the fuel handling accident by restricting direct air flow from the containment to the environment.

The containment air locks, which are also part of the containment pressure boundary, provide a means for personnel access during MODES 1, 2, 3, and 4 unit operation in accordance with LCO 3.6.2, "Containment Air Locks." Each air lock has a door at both ends. The doors are normally interlocked to prevent simultaneous opening when containment OPERABILITY is required. During periods of unit shutdown when containment closure is not required, the door interlock mechanism may be disabled, allowing both doors of an air lock to remain open for extended periods when frequent containment entry is necessary. During CORE ALTERATIONS or movement of irradiated fuel assemblies within containment, containment closure is required; therefore, the door interlock mechanism may remain disabled, but one air lock door must always remain closed.

The requirements for containment penetration closure ensure that a release of fission product radioactivity within containment will be restricted from escaping to the environment. The closure restrictions are sufficient to restrict fission product radioactivity release from containment due to a fuel handling accident during refueling.

The Containment Purge System consists of the 36-inch containment purge supply and exhaust ducts. The supply system includes roughing filters, heating coils, fan and a containment penetration with two butterfly valves for isolation. The exhaust system includes a containment penetration with two butterfly valves for isolation and can be aligned to discharge to the atmosphere through the plant vent either directly or through the Containment Purge Filter System (i.e., a filter bank with roughing, HEPA and charcoal filters).

BASES

BACKGROUND (Continued)

The Containment Purge System must be isolated when in Modes 1, 2, 3 or 4 in accordance with requirements established in LCO 3.6.3, Containment Isolation Valves. In Modes 5 and 6, the Containment Purge System may be used for containment ventilation. When open, the Containment Purge System isolation valves are capable of closing in response to the detection of high radiation levels in accordance with requirements established in LCO 3.3.6, Containment Purge and Pressure Relief Isolation Instrumentation (Ref. 1). Despite this isolation capability, the Containment Purge System must be aligned to discharge through the Containment Purge Filter System during CORE ALTERATIONS or movement of irradiated fuel until the reactor has been shutdown for a specified minimum number of hours.

The Containment Pressure Relief Line (i.e., Containment Vent) consists of a single 10-inch containment vent line that is used to handle normal pressure changes in the Containment when in Modes 1, 2, 3 and 4 (Ref. 1). The Containment Pressure Relief Line is equipped with three quick-closing butterfly type isolation valves, one inside and two outside the containment which isolate automatically in accordance with requirements established in LCO 3.3.2, "Engineered Safety Feature Actuation System (ESFAS) Instrumentation", and LCO 3.3.6, "Containment Purge System and Pressure Relief Line Isolation Instrumentation." Although the Containment Pressure Relief Line discharges to the atmosphere via the Containment Auxiliary Charcoal Filter System (i.e., a filter bank with roughing, HEPA and charcoal filters), the Containment Pressure Relief Line must remain isolated during CORE ALTERATIONS or movement of irradiated fuel until the reactor has been shutdown for a specified minimum number of hours. The Containment Pressure Relief Line must remain isolated because the Containment Auxiliary Charcoal Filter System is not required to be tested in accordance with Specification 5.5.10, Ventilation Filter Test Program.

The other containment penetrations that provide direct access from containment atmosphere to outside atmosphere must be isolated on at least one side. Isolation may be achieved by an OPERABLE automatic isolation valve, or by a manual isolation valve, blind flange, or equivalent. Equivalent isolation methods

BASES

BACKGROUND (Continued)

must be approved in accordance with 10 CFR 50.59 and may include use of a material that can provide a temporary, atmospheric pressure, ventilation barrier for the other containment penetrations during fuel movements.

APPLICABLE SAFETY ANALYSES

During CORE ALTERATIONS or movement of irradiated fuel assemblies within containment, the most severe radiological consequences result from a fuel handling accident. The fuel handling accident is a postulated event that involves damage to irradiated fuel (Ref. 2). Fuel handling accidents, analyzed in Reference 2, include dropping a single irradiated fuel assembly and handling tool or a heavy object onto other irradiated fuel assemblies. The release of radioactivity from the containment following a fuel handling accident is limited by the following:

a) The requirements of LCO 3.9.6, "Refueling Cavity Water Level;"

b) The minimum decay time of 145 hours prior to CORE ALTERATIONS; and,

c) The requirements of this LCO to either isolate the Containment Purge System or align the system to discharge through the HEPA filters and charcoal adsorbers for a minimum of first 550 hours following the reactor shutdown.

This combination of requirements ensures that the release of fission product radioactivity, subsequent to a fuel handling accident, results in doses that are well within the guideline values specified in 10 CFR 100. Standard Review Plan, Section 15.7.4, Rev. 1 (Ref. 3), defines "well within" 10 CFR 100 to be 25% or less of the 10 CFR 100 values. The acceptance limits for offsite radiation exposure will be 25% of 10 CFR 100 values or the NRC staff approved licensing basis (e.g., a specified fraction of 10 CFR 100 limits).

BASES

APPLICABLE SAFETY ANALYSES (continued)

Containment penetrations satisfy Criterion 3 of 10 CFR 50.36.

LCO

This LCO limits the consequences of a fuel handling accident in containment by limiting the potential escape paths for fission product radioactivity released within containment. The LCO requires any penetration providing direct access from the containment atmosphere to the outside atmosphere to be closed except for the OPERABLE containment purge system penetrations. For the OPERABLE containment purge system penetrations, this LCO ensures that these penetrations are isolable by the Containment Purge isolation instrumentation. Additionally, the requirement to isolate the Containment Purge System or align the system to discharge through the HEPA filters and charcoal adsorbers for a minimum of the first 550 hours following the reactor shutdown is required to limit offsite radiation exposure to within required limits. The Containment Pressure Relief Line must remain isolated because the Containment Auxiliary Charcoal Filter System is not required to be tested in accordance with Specification 5.5.10, Ventilation Filter Test Program. The OPERABILITY requirements for this LCO ensure that the automatic purge system valves meet the assumptions used in the safety analysis to ensure that releases through the valves are filtered and can be terminated, such that radiological doses are within the acceptance limit.

APPLICABILITY

The containment penetration requirements are applicable during CORE ALTERATIONS or movement of irradiated fuel assemblies within containment because this is when there is a potential for a fuel handling accident. In MODES 1, 2, 3, and 4, containment penetration requirements are addressed by LCO 3.6.1. In MODES 5 and 6, when CORE ALTERATIONS or movement of irradiated fuel assemblies within containment are not being conducted, the potential for a fuel handling accident does not exist. Therefore, under these conditions no requirements are placed on containment penetration status.

BASES

ACTIONS

A.1 and A.2

If the containment equipment hatch, air locks, or any containment penetration that provides direct access from the containment atmosphere to the outside atmosphere is not in the required status, including the Containment Purge system isolation instrumentation not capable of automatic actuation when the purge and exhaust valves are open, the unit must be placed in a condition where the isolation function is not needed. This is accomplished by immediately suspending CORE ALTERATIONS and movement of irradiated fuel assemblies within containment. Performance of these actions shall not preclude completion of movement of a component to a safe position.

SURVEILLANCE REQUIREMENTS

SR 3.9.3.1

This Surveillance demonstrates that each of the containment penetrations required to be in its closed position is in that position. The Surveillance on the open purge and exhaust valves will demonstrate that the valves are not blocked from closing. Also the Surveillance will demonstrate that each valve operator has motive power, which will ensure that each valve is capable of being closed by an OPERABLE automatic containment purge and exhaust isolation signal.

The Surveillance is performed every 7 days during CORE ALTERATIONS or movement of irradiated fuel assemblies within containment. The Surveillance interval is selected to be commensurate with the normal duration of time to complete fuel handling operations. A surveillance before the start of refueling operations will provide two or three surveillance verifications during the applicable period for this LCO. As such, this Surveillance ensures that a postulated fuel handling accident that releases fission product radioactivity within the containment will not result in a release of fission product radioactivity to the environment.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.9.3.2

This SR requires periodic verification every 7 days that the Containment Building Vent and Purge System is either isolated or aligned to discharge through the HEPA filters and charcoal adsorbers. This SR is needed because it requires periodic verification that LCO 3.9.3.d is being met. A Note provides the allowance that this SR is not required to be performed or met if the reactor has been subcritical for ≥ 550 hours. These restrictions ensure that the offsite dose limit for a fuel handling accident of 75 rem to the thyroid at the exclusion area boundary (i.e., 25 percent of the 10 CFR Part 100 limit of 300 rem) is met by either filtering any release from the containment or by allowing a greater decay time before fuel handling activities are permitted.

SR 3.9.3.3

This Surveillance demonstrates that each containment purge and exhaust valve actuates to its isolation position on an actual or simulated high radiation signal. The 92 day Frequency ensures that this SR is performed prior to this function being required and periodically thereafter. In LCO 3.3.6, the Containment Purge system isolation instrumentation requires a CHANNEL CHECK every 12 hours and a COT every 92 days to ensure the channel OPERABILITY during refueling operations. Every 24 months a CHANNEL CALIBRATION is performed. SR 3.6.3.5 demonstrates that the isolation time of each valve is in accordance with the Inservice Testing Program requirements. These Surveillances performed during MODE 6 will ensure that the valves are capable of closing after a postulated fuel handling accident to limit a release of fission product radioactivity from the containment.

SR 3.9.3.4

This SR verifies that the required Containment Building Purge System testing is performed in accordance with Specification 5.5.10, Ventilation Filter Test Program (VFTP). The VFTP includes testing HEPA filter performance, charcoal adsorber efficiency, minimum system flow rate, and the physical properties

BASES

SURVEILLANCE REQUIREMENTS

SR 3.9.3.4 (continued)

of the activated charcoal (general use and following specific operations). Specific test frequencies and additional information are discussed in detail in the VFTP.

REFERENCES

1. FSAR, Section 5.3.
2. FSAR, Section 14.2.
3. NUREG-0800, Section 15.7.4, Rev. 1, July 1981.

B 3.9 REFUELING OPERATIONS

B 3.9.4 Residual Heat Removal (RHR) and Coolant Circulation – High Water Level

BASES

BACKGROUND

The purpose of the RHR System in MODE 6 is to remove decay heat and sensible heat from the Reactor Coolant System (RCS), as required by GDC 34, to provide mixing of borated coolant and to prevent boron stratification (Ref. 1). Heat is removed from the RCS by circulating reactor coolant through the RHR heat exchanger(s), where the heat is transferred to the Component Cooling Water System. The coolant is then returned to the RCS via the RCS cold leg(s). Operation of the RHR System for normal cooldown or decay heat removal is manually accomplished from the control room. The heat removal rate is adjusted by controlling the flow of reactor coolant through the RHR heat exchanger(s) or regulating service water or component cooling water flow. Mixing of the reactor coolant is maintained by this continuous circulation of reactor coolant through the RHR System.

APPLICABLE SAFETY ANALYSES

If the reactor coolant temperature is not maintained below 200°F, boiling of the reactor coolant could result. This could lead to a loss of coolant in the reactor vessel. Additionally, boiling of the reactor coolant could lead to a reduction in boron concentration in the coolant due to boron plating out on components near the areas of the boiling activity. The loss of reactor coolant and the reduction of boron concentration in the reactor coolant would eventually challenge the integrity of the fuel cladding, which is a fission product barrier. One train of the RHR System is required to be operational in MODE 6, with the water level ≥ 23 ft above the top of the reactor vessel flange, to prevent this challenge. The LCO does permit securing the RHR pump for short durations, under the condition that the boron concentration is not diluted. This conditional securing of the RHR pump does not result in a challenge to the fission product barrier.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The RHR System meets Criterion 4 of 10 CFR 50.36.

LCO

Only one RHR loop is required for decay heat removal in MODE 6, with the water level ≥ 23 ft above the top of the reactor vessel flange. Only one RHR loop is required to be OPERABLE, because the volume of water above the reactor vessel flange provides backup decay heat removal capability. At least one RHR loop must be OPERABLE and in operation to provide:

a. Removal of decay heat;

b. Mixing of borated coolant to minimize the possibility of criticality; and

c. Indication of reactor coolant temperature.

An OPERABLE RHR loop includes an RHR pump, a heat exchanger, valves, piping, instruments, and controls to ensure an OPERABLE flow path. The flow path starts in loop 32 RCS hot leg and is returned to the RCS cold legs.

The LCO is modified by a Note that allows the required operating RHR loop to be removed from service for up to 1 hour per 8 hour period, provided no operations are permitted that would cause a reduction of the RCS boron concentration. Boron concentration reduction is prohibited because uniform concentration distribution cannot be ensured without forced circulation. This permits operations such as core mapping or alterations in the vicinity of the reactor vessel hot leg nozzles and RCS to RHR isolation valve testing. During this 1 hour period, decay heat is removed by natural convection to the large mass of water in the refueling cavity.

APPLICABILITY

One RHR loop must be OPERABLE and in operation in MODE 6, with the water level ≥ 23 ft above the top of the reactor vessel flange, to provide decay heat removal. The 23 ft water level was

BASES

APPLICABILITY (continued)

selected because it corresponds to the 23 ft requirement established for fuel movement in LCO 3.9.6, "Refueling Cavity Water Level." Requirements for the RHR System in other MODES are covered by LCOs in Section 3.4," Reactor Coolant System (RCS)", and Section 3.5, "Emergency Core Cooling Systems (ECCS)." RHR loop requirements in MODE 6 with the water level < 23 ft are located in LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation – Low Water Level."

ACTIONS

RHR loop requirements are met by having one RHR loop OPERABLE and in operation, except as permitted in the Note to the LCO.

A.1

If RHR loop requirements are not met, there will be no forced circulation to provide mixing to establish uniform boron concentrations.

A.2

If RHR loop requirements are not met, actions shall be taken immediately to suspend loading of irradiated fuel assemblies in the core. With no forced circulation cooling, decay heat removal from the core occurs by natural convection to the heat sink provided by the water above the core. A minimum refueling water level of 23 ft above the reactor vessel flange provides an adequate available heat sink. Suspending any operation that would increase decay heat load, such as loading a fuel assembly, is a prudent action under this condition.

A.3

If RHR loop requirements are not met, actions shall be initiated and continued in order to satisfy RHR loop requirements. With the unit in MODE 6 and the refueling water level ≥ 23 ft above the top of the reactor vessel flange, corrective actions shall be initiated immediately.

BASES

ACTIONS (continued)

A.4

If RHR loop requirements are not met, all containment penetrations providing direct access from the containment atmosphere to the outside atmosphere must be closed, using at least a single barrier, within 4 hours. With the RHR loop requirements not met, the potential exists for the coolant to boil and release radioactive gas to the containment atmosphere. Closing containment penetrations that are open to the outside atmosphere ensures dose limits are not exceeded.

The Completion Time of 4 hours is reasonable, based on the low probability of the coolant boiling in that time.

SURVEILLANCE REQUIREMENTS

SR 3.9.4.1

This Surveillance demonstrates that the RHR loop is in operation and circulating reactor coolant. The flow rate is determined by the flow rate necessary to provide sufficient decay heat removal capability and to prevent thermal and boron stratification in the core. The Frequency of 12 hours is sufficient, considering the flow, temperature, pump control, and alarm indications available to the operator in the control room for monitoring the RHR System.

REFERENCES

1. FSAR, Section 6.2.

B 3.9 REFUELING OPERATIONS

B 3.9.5 Residual Heat Removal (RHR) and Coolant Circulation - Low Water Level

BASES

BACKGROUND

The purpose of the RHR System in MODE 6 is to remove decay heat and sensible heat from the Reactor Coolant System (RCS), as required by GDC 34, to provide mixing of borated coolant, and to prevent boron stratification (Ref. 1). Heat is removed from the RCS by circulating reactor coolant through the RHR heat exchangers where the heat is transferred to the Component Cooling Water System. The coolant is then returned to the RCS via the RCS cold leg(s). Operation of the RHR System for normal cooldown decay heat removal is manually accomplished from the control room. The heat removal rate is adjusted by controlling the flow of reactor coolant through the RHR heat exchanger(s) or regulating service water or component cooling water flow. Mixing of the reactor coolant is maintained by this continuous circulation of reactor coolant through the RHR System.

APPLICABLE SAFETY ANALYSES

If the reactor coolant temperature is not maintained below 200°F, boiling of the reactor coolant could result. This could lead to a loss of coolant in the reactor vessel. Additionally, boiling of the reactor coolant could lead to a reduction in boron concentration in the coolant due to the boron plating out on components near the areas of the boiling activity. The loss of reactor coolant and the reduction of boron concentration in the reactor coolant will eventually challenge the integrity of the fuel cladding, which is a fission product barrier. Two trains of the RHR System are required to be OPERABLE, and one train in operation, in order to prevent this challenge.

The RHR System meets criterion 4 of 10 CFR 50.36.

BASES

LCO

In MODE 6, with the water level < 23 ft above the top of the reactor vessel flange, both RHR loops must be OPERABLE. Additionally, one loop of RHR must be in operation in order to provide:

a. Removal of decay heat;

b. Mixing of borated coolant to minimize the possibility of criticality; and

c. Indication of reactor coolant temperature.

An OPERABLE RHR loop consists of an RHR pump, a heat exchanger, valves, piping, instruments and controls to ensure an OPERABLE flow path. The flow path starts in loop 32 RCS hot leg and is returned to the RCS cold legs.

APPLICABILITY

Two RHR loops are required to be OPERABLE, and one RHR loop must be in operation in MODE 6, with the water level < 23 ft above the top of the reactor vessel flange, to provide decay heat removal. Requirements for the RHR System in other MODES are covered by LCOs in Section 3.4, Reactor Coolant System (RCS), and Section 3.5, Emergency Core Cooling Systems (ECCS). RHR loop requirements in MODE 6 with the water level ≥ 23 ft are located in LCO 3.9.4, "Residual Heat Removal (RHR) and Coolant Circulation - High Water Level."

ACTIONS

A.1 and A.2

If less than the required number of RHR loops are OPERABLE, action shall be immediately initiated and continued until the RHR loop is restored to OPERABLE status and to operation or until ≥ 23 ft of water level is established above the reactor vessel flange. When the water level is ≥ 23 ft above the reactor vessel flange, the Applicability changes to that of LCO 3.9.4, and only one RHR loop is required to be OPERABLE and in operation. An immediate Completion Time is necessary for an operator to initiate corrective actions.

BASES

ACTIONS (continued)

B.1

If no RHR loop is in operation, there will be no forced circulation to provide mixing to establish uniform boron concentrations.

B.2

If no RHR loop is in operation, actions shall be initiated immediately, and continued, to restore one RHR loop to operation. Since the unit is in Conditions A and B concurrently, the restoration of two OPERABLE RHR loops and one operating RHR loop should be accomplished expeditiously.

B.3

If no RHR loop is in operation, all containment penetrations providing direct access from the containment atmosphere to the outside atmosphere must be closed, using at least a single barrier, within 4 hours. With the RHR loop requirements not met, the potential exists for the coolant to boil and release radioactive gas to the containment atmosphere. Closing containment penetrations that are open to the outside atmosphere ensures that dose limits are not exceeded.

The Completion Time of 4 hours is reasonable, based on the low probability of the coolant boiling in that time.

SURVEILLANCE REQUIREMENTS

SR 3.9.5.1

This Surveillance demonstrates that one RHR loop is in operation and circulating reactor coolant. The flow rate is determined by the flow rate necessary to provide sufficient decay heat removal capability and to prevent thermal and boron stratification in the

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SURVEILLANCE REQUIREMENTS

SR 3.9.5.1 (continued)

core. In addition, during operation of the RHR loop with the water level in the vicinity of the reactor vessel nozzles, the RHR pump suction requirements must be met. The Frequency of 12 hours is sufficient, considering the flow, temperature, pump control, and alarm indications available to the operator for monitoring the RHR System in the control room.

SR 3.9.5.2

Verification that the required pump is OPERABLE ensures that an additional RCS or RHR pump can be placed in operation, if needed, to maintain decay heat removal and reactor coolant circulation. Verification is performed by verifying proper breaker alignment and power available to the required pump. The Frequency of 7 days is considered reasonable in view of other administrative controls available and has been shown to be acceptable by operating experience.

REFERENCES

1. FSAR, Section 6.2.

B 3.9 REFUELING OPERATIONS

B 3.9.6 Refueling Cavity Water Level

BASES

BACKGROUND

The movement of irradiated fuel assemblies or performance of CORE ALTERATIONS, except during latching and unlatching of control rod drive shafts, within containment requires a minimum water level of 23 ft above the top of the reactor vessel flange. During refueling, this maintains sufficient water level in the containment, refueling canal, fuel transfer canal, refueling cavity, and spent fuel pit. Sufficient water is necessary to retain iodine fission product activity in the water in the event of a fuel handling accident (Refs. 1 and 2). Sufficient iodine activity would be retained to limit offsite doses from the accident to < 25% of 10 CFR 100 limits, as provided by the guidance of Reference 3.

APPLICABLE SAFETY ANALYSES

During CORE ALTERATIONS and movement of irradiated fuel assemblies, the water level in the refueling canal and the refueling cavity is an initial condition design parameter in the analysis of a fuel handling accident in containment, as postulated by Regulatory Guide 1.25 (Ref. 1). A minimum water level of 23 ft (Regulatory Position C.1.c of Ref. 1) allows a decontamination factor of 100 (Regulatory Position C.1.g of Ref. 1) to be used in the accident analysis for iodine. This relates to the assumption that 99% of the total iodine released from the pellet to cladding gap of all the dropped fuel assembly rods is retained by the refueling cavity water. The fuel pellet to cladding gap is assumed to contain 10% of the total fuel rod iodine inventory (Ref. 1).

The fuel handling accident analysis inside containment is described in Reference 2. With a minimum water level of 23 ft and a minimum decay time of 145 hours prior to fuel handling, the analysis and test programs demonstrate that the iodine release due to a postulated fuel handling accident is adequately captured by the water and offsite doses are maintained within allowable

BASES

APPLICABLE SAFETY ANALYSES (continued)

limits (Refs. 4 and 5). The amount of radioactivity potentially released following a fuel handling accident inside containment is further reduced by the following: a) requirements in the FSAR that delay any movement of irradiated fuel until the reactor has been subcritical for at least 145 hours; and, LCO 3.9.3, "Containment Penetrations," which requires the use of HEPA and charcoal filtration on the containment purge and pressure relief path for the first 550 hours following reactor shutdown if Vantage+ fuel is used. These additional restrictions ensure that does rates at the site boundary are well within the 10 CFR Part 100 limit of 300 rem to the thyroid following a fuel handling accident inside containment (Ref. 6).

Further reductions in the amount of radioactivity potentially released following a fuel handling accident inside containment are expected because the containment will be isolated either automatically or through operator action following a fuel handling accident. Specifically, LCO 3.3.6, "Containment Purge System and Pressure Relief Line Isolation Instrumentation," requires the Operability of radiogas monitors R-11 and R-12, either of which could generate an automatic isolation signal, during the movement of irradiated fuel.

Refueling cavity water level satisfies Criterion 2 of 10 CFR 50.36.

LCO

A minimum refueling cavity water level of 23 ft above the reactor vessel flange is required to ensure that the radiological consequences of a postulated fuel handling accident inside containment are within acceptable limits, as provided by the guidance of Reference 3.

APPLICABILITY

LCO 3.9.6 is applicable during CORE ALTERATIONS, except during latching and unlatching of control rod drive shafts, and when moving irradiated fuel assemblies within containment. The LCO

BASES

APPLICABILITY (continued)

minimizes the possibility of a fuel handling accident in containment that is beyond the assumptions of the safety analysis. If irradiated fuel assemblies are not present in containment, there can be no significant radioactivity release as a result of a postulated fuel handling accident. Requirements for fuel handling accidents in the spent fuel pool are covered by LCO 3.7.14, "Spent Fuel Pit Water Level."

ACTIONS

A.1 and A.2

With a water level of < 23 ft above the top of the reactor vessel flange, all operations involving CORE ALTERATIONS or movement of irradiated fuel assemblies within the containment shall be suspended immediately to ensure that a fuel handling accident cannot occur.

The suspension of CORE ALTERATIONS and fuel movement shall not preclude completion of movement of a component to a safe position.

SURVEILLANCE REQUIREMENTS

SR 3.9.6.1

Verification of a minimum water level of 23 ft above the top of the reactor vessel flange ensures that the design basis for the analysis of the postulated fuel handling accident during refueling operations is met. Water at the required level above the top of the reactor vessel flange limits the consequences of damaged fuel rods that are postulated to result from a fuel handling accident inside containment (Ref. 2).

BASES

SURVEILLANCE REQUIREMENTS

SR 3.9.6.1 (continued)

The Frequency of 24 hours is based on engineering judgment and is considered adequate in view of the large volume of water and the normal procedural controls of valve positions, which make significant unplanned level changes unlikely.

REFERENCES

1. Regulatory Guide 1.25, March 23, 1972.
2. FSAR, Section 14.2.
3. NUREG-0800, Section 15.7.4.
4. 10 CFR 100.10.
5. Malinowski, D. D., Bell, M. J., Duhn, E., and Locante, J., WCAP-828, Radiological Consequences of a Fuel Handling Accident, December 1971.
6. Safety Evaluation Report for Amendment No. 175 to Facility Operating License No. DPR-64, July 17, 1997.