SUPPLEMENT 8
CONVERSION PACKAGE SECTION 3.1
PAGE INSERTION INSTRUCTIONS

Remove and insert the following pages into Enclosure 9 to Serial: RNP-RA/96-0141.

	Remove Page	Insert Page
j.	Part 10. "ISTS Generic Changes"	
	NA	NA

A1

See ITS 3.3.1

TABLE 3.5-2 (Continued)

REACTOR TRIP INSTRUMENTATION LIMITING OPERATING CONDITIONS

NO.	FUNCTIONAL UNIT	1 TOTAL NO. OF CHANNELS	2 MINIMUM CHANNELS OPERABLE	3 OPERATOR ACTION IF COLUMN 1 OR 2 CANNOT BE MET	APPLICABLE CONDITIONS
11.	Turbine Trip				
	A. Auto Stop Oil Pressure	3	2	ACTION 6	*****
	B. Turb Stop Valves	2	2	ACTION 6	*****
12.	Lo Lo Steam Generator Water Level	3/SG	2/SG	ACTION 6	Reactor Critical
13.	Underfrequency 4 KV System	3	2	ACTION 6	Reactor Critical
14.	Undervoltage on 4 KV System	3	2	ACTION 6	Reactor Critical
15.	Control Rod Misalignment Monitor				Modes 1 and 2 — M30
	A. ERFIS Rod Position Deviation	1	1	ACTION 9	Reactor Critical
	B. Quadrant Power Tilt Monitor (upper and lower ex-core neutron detectors) "Detector Current Comparator"	1	1	ACTION 10	>50% of rated power

See ITS 3.3.1

Supplement 8

See ITS 3.3.1

A1

TABLE 3.5-2 (Continued)

REACTOR TRIP INSTRUMENTATION LIMITING OPERATING CONDITIONS

TABLE NOTATIONS

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

ACTION 5 With the number of OPERABLE channels one less than the Minimum Channels OPERABLE requirement, verify compliance with Shutdown Margin within 1 hour and at least once per 12 hours thereafter.

ACTION 6 With the number of OPERABLE channels one less than the Total Number of Channels, Startup and/or Power Operation may proceed until performance of the next required operational test provided the inoperable channel is placed into the tripped condition within 1 hour.

ACTION 7 With the number of OPERABLE channels one less than the Total Number of Channels, place the inoperable channel into the tripped condition within 1 hour, and restore the inoperable channel to OPERABLE status within 7 days or be in at least the Hot Shutdown Condition within the next 8 hours.

ACTION 8 With the number of OPERABLE channels one less than the Minimum Channels OPERABLE requirement, restore the inoperable channel to OPERABLE status within 48 hours or open the Reactor Trip Breakers within the next hour.

L8

SR 3.1.4.1 2nd frequency

ACTION 9 Log individual rod position within ~~1 hour~~ 4 hours and every ~~hour~~ 2 hours thereafter, ~~and following load changes of~~ >10% of rated power, or after >30 inches of control rod motion. In addition to the above ACTIONS, if both rod misalignment monitors (15.A and 15.B) are inoperable with reactor power >50% of rated power for 2 hours or more, the nuclear overpower trip shall be reset to ≤ 93% or rated power.

ACTION 10 Log individual upper and lower ion chamber currents within 1 hour and every hour thereafter, and following load changes of >10% of rated power, or abover >30 inches of control rod motion. In addition to the above ACTIONS, if both rod misalignment monitors (15.A and 15.B) are inoperable with reactor power >50% of rated power for two hours or more, the nuclear overpower trip shall be reset to ≤ 93 percent of rated power.

See ITS 3.3.1

Specification 3.1.4

A1

ITS

TABLE 4.1-3

FREQUENCIES FOR EQUIPMENT TESTS

L3

M11

Not fully Inserted

≥ 10 steps

92 days

		Check	Frequency	Maximum Time Between Tests
[SR 3.1.4.3] 1.	Control Rods	Rod drop times of all full length rods	Each refueling shutdown	NA* L3
[SR 3.1.4.2] 2.	Control Rod	~~Partial~~ movement of all full length rods	~~Every 2 weeks during reactor critical operations~~	~~20 days~~
3.	Pressurizer Safety Valves	Set point	Each refueling shutdown	NA See 3.4.10
4.	Main Steam Safety Valves	~~Verify each~~ required MSSV lift setpoint per Table 4.1-4 in accordance with the Inservice Testing Program. Following testing, lift setting shall be within +/- 1%.	In accordance with the Inservice Testing Program	NA See 3.7.1
5.	Containment Isolation Trip	Functioning	Each refueling shutdown	NA See 3.6.3 3.3.2
6.	Refueling System Interlocks	Functioning	Prior to each refueling shutdown	NA See 3.9.1
7.	Service Water System	Functioning	Each refueling shutdown	NA See 3.7.7
~~8.~~	~~DELETED~~			
9.	Primary System Leakage	Evaluate	Daily when reactor coolant system is above cold shutdown condition	NA See 3.4.13
10.	Diesel Fuel Supply	Fuel Inventory	Weekly	10 days See 3.8.3
~~11.~~	~~DELETED~~			
12.	Turbine Steam Stop, Control, Reheat Stop, and Interceptor Valves	Closure	Quarterly during power operation and prior to startup	115 days See 3.7.1

Add SR 3.1.4.1 and first frequency

M12

M12 A CTS surveillance requirement comparable to ITS SR 3.1.4.1, when the rod position deviation monitor is OPERABLE, does not exist. SR 3.1.4.1 requires periodic verification that individual rods are within alignment limits when the rod position deviation monitor is OPERABLE. This is necessary to provide periodic confirmation the unit is operated with the requirements of the LCO. This SR is considered a reasonable verification of the associated requirement. This is an additional restriction on plant operation and is consistent with NUREG-1431.

M13 CTS 3.10.1.2 is applicable when the reactor is critical. ITS 3.1.5 is applicable in MODE 1 and MODE 2 with any control bank not fully inserted. The inclusion of this additional applicability is required to ensure operation is within the bounds of the applicable safety analysis. This is an additional restriction on plant operation and is consistent with NUREG-1431.

M14 CTS required actions comparable to ITS 3.1.5 RAs A.1.1, A.1.2, A.2 and B.1 do not exist. Lacking specified actions, failure to satisfy CTS 3.10.1.2 requires compliance with CTS 3.0. In this case CTS 3.0 requires hot shutdown in 8 hours. ITS 3.1.5 RAs A.1.1, A.1.2, A.2 and B.1 mandate actions which can require the unit be placed in Hot Shutdown in 8 hours, the same as CTS 3.0. RA A.1.1 require verification that SDM is within limits within one hour. RA A.1.2 requires initiation of boration within one hour to restore SDM to within limits. RA A.2 requires the shutdown banks be restored to within limits within 2 hours. Requiring either verification of SDM or initiation of action to restore SDM is necessary since available SDM may be significantly reduced. Requiring restoration of the shutdown banks to within limits within 2 hours is necessary to prevent remaining in an unacceptable condition for an extended period of time. If any Required Action and Associated Completion Time are not met, RA B.2 requires the unit be placed in MODE 3. The requirement to place the unit in MODE 3 is necessary to place the unit in a MODE outside the Applicability of the specification. These additional actions are more restrictive on plant operation and are consistent with NUREG-1431.

M15 A CTS surveillance comparable to ITS SR 3.1.5.1 does not exist. SR 3.1.5.1 requires periodic verification that the shutdown banks are within specified limits. This is necessary to periodically confirm that operation is within the limits of the LCO. This SR is considered a reasonable verification of the associated requirement. The addition of ITS SR 3.1.5.1 is an additional restriction on plant operation and is consistent with NUREG-1431.

M16 CTS 3.10.1.3 does not impose explicit restrictions on sequence and overlap. These restrictions are explicitly incorporated in ITS LCO 3.1.6. The inclusion of these restrictions is required to ensure

operation within the bounds of the applicable safety analysis. These are additional restrictions on plant operation and are consistent with NUREG-1431.

M17 CTS required actions comparable to ITS 3.1.6 RAs A.1.1, A.1.2, B.1.1, B.1.2, and B.2 do not exist. With control bank insertion limits not met, RA A.1.1 require verification that SDM is within limits within one hour. RA A.1.2 requires initiation of boration within one hour to restore SDM to within limits. RA A.2 requires the control banks be restored to within limits within 1 hour. Requiring either verification of SDM or initiation of action to restore SDM is necessary since available SDM may be significantly reduced. Requiring restoration of the control banks to within limits within 1 hour is necessary to prevent remaining in an unacceptable condition for an extended period of time. With control bank insertion limits not met, RA B.1.1 require verification that SDM is within limits within one hour. RA B.1.2 requires initiation of boration within one hour to restore SDM to within limits. Requiring either verification of SDM or initiation of action to restore SDM is necessary since available SDM may be significantly reduced. RA B.2 requires the sequence and overlap be restored to within limits within 2 hours. Requiring restoration of the sequence and overlap to within limits within 2 hours is necessary to prevent remaining in an unacceptable condition for an extended period of time. If any Required Action and Associated Completion Time are not met, RA C.1 requires the unit be placed in MODE 3. The requirement to place the unit in MODE 3 is necessary to place the unit in a MODE outside the Applicability of the specification. The inclusion of these RAs is considered reasonable to ensure operation within the bounds of the applicable safety analysis. These are additional restrictions on plant operation and are consistent with NUREG-1431.

M18 CTS surveillance requirements comparable to ITS SRs 3.1.6.1, 3.1.6.2 and 3.1.6.3 do not exist. SR 3.1.6.1 requires verification that critical bank position is within limits. This Surveillance is required to ensure that the reactor does not achieve criticality with the control banks below their insertion limits. SR 3.1.6.2 requires periodic verification that control bank insertion is within limits. This SR is necessary to detect control banks which may be approaching there insertion limits. SR 3.1.6.3 requires periodic verification that sequence and overlap are within limits for control banks not fully withdrawn from the core. This SR is necessary to detect control banks which may be outside sequence and overlap limits. These SRs are considered a reasonable verification of the associated requirements. The addition of these SRs is an additional restriction on plant operation and is consistent with NUREG-1431.

M19 Not used.

M30 The requirements of CTS item 15.A (ERFIS rod position deviation monitor) and associated ACTION 9 are applicable when the reactor is critical. ITS 3.1.4 is applicable in MODES 1 and 2. In MODES 1 and 2, neutron power is generated and alignment has the potential to affect the safety of the plant. The inclusion of this additional applicability is required to ensure operation is within the applicable safety analysis. This is an additional restriction on plant operation and is consistent with NUREG-1431.

within limits. Both actions result in the addition of negative reactivity and a return to compliance with the assumptions of the safety analysis. ITS 3.1.1 RA A.1 requires timely restoration of SDM. Timely restoration of SDM is preferred to imposing the increased risk associated with a plant shutdown transient. Additionally, mandating shutdown of the unit may not be the safest course of action while sufficient SDM is not available. The proposed change provides an appropriate specific action for failing to satisfy the LCO instead of applying the generic action mandated by CTS 3.0. This change is consistent with NUREG-1431.

L2 This change involves two separate aspects both of which are analyzed separately here.

With the MTC outside the limits provided in the COLR, CTS 3.1.3.3 requires the reactor be made subcritical by an amount greater than or equal to the potential reactivity insertion due to depressurization. No completion time is explicitly stated. In this condition, CTS 3.0 requires hot shutdown be achieved within 8 hours. With MTC not within the upper limit, ITS 3.1.3 RA A.1 mandates establishment of administrative withdrawal limits for control banks to maintain MTC within the upper limit with a completion time of 24 hours. Provided ITS 3.1.3 RA A.1 is satisfied, no further action is required. Establishment of administrative withdrawal limits for control banks to maintain MTC within the upper limit is not precluded by CTS. However, the completion time of 24 hours to establish administrative control banks withdrawal limits is less restrictive than CTS permits.

With the required action or associated completion time of ITS 3.1.3 RA A.1 not met, ITS 3.1.3 RA B.1 mandates being in MODE 2 with $K_{eff} < 1.0$ within 6 hours. This completion time is in addition to the 24 hours permitted by ITS 3.1.3 RA A.1, and is less restrictive than CTS permits.

A specific Completion Time is added to CTS 3.1.3.3 to restore MTC to within the upper limit (i.e., to "Establish administrative withdrawal limits for control banks to maintain MTC within limits"). Evaluating the MTC measurement and obtaining the necessary input to compute the necessary bank withdrawal limits necessary to restore compliance with the MTC limits may require a time period much longer than 8 hours, which is the CTS required time to place the plant in a non-applicable MODE. The completion time of 24 hours for ITS 3.1.3 Required Action A.1 provides sufficient time for evaluating the MTC measurement and computing the required bank withdrawal limits. Measurement of MTC to determine that MTC is within the upper limit occurs during physiscs tests at the beginning of cycle at low power levels (i.e., MODE 2). At this time in the operating cycle, MTC is at its most positive value. If measurement of MTC indicates that MTC is above the upper limit, the

power range low neutron flux trip protects the reactor fuel under these conditions. In order to satisfy Required Action A.1, the reactor coolant system boron concentration will be diluted and control or shutdown banks will be inserted in accordance with their sequence and overlap requirements to establish the required withdrawal limits in order to assure that the MTC upper limit is met. If after 24 hours of dilution, rod insertion, and MTC measurement, the MTC is not established to within the upper limit, the prediction of core reactivity in the core reload analysis is seriously in question, and shutdown in accordance with Required Action B.1 is appropriate to reevaluate the core analyses. Additionally, the 24 hour Completion Time is based on the low probability of an accident occurring during this period and takes into consideration the fact that as cycle burnup is increased, RCS boron concentration is reduced which causes MTC to become more negative. This change also provides the benefit of not hastily inducing a plant shutdown transient while in a condition where unit response during postulated events may not be as predicted (due to MTC not being within the upper limit).

With MTC outside the limits provided in the COLR, CTS 3.1.3.3 mandates being subcritical by an amount equal to the potential reactivity insertion due to depressurization. With MTC outside the upper limit, ITS 3.1.3 RA B.1 mandates, assuming ITS 3.1.3 RA A.1 and associated completion time not met, being in MODE 2 with $K_{eff} < 1.0$. In this condition, the SDM requirements of ITS LCO 3.1.1 are applicable requiring the SDM be within the limits provided in the COLR. The COLR includes appropriate SDM limits for this condition. Therefore this aspect of the change is administrative in nature.

L3 CTS Table 4.1-3, Item 2 requires verification of each control rods freedom of movement every 14 days during reactor critical operations. ITS SR 3.1.4.2 requires this surveillance to be performed at a 92 day Frequency and excludes control rods that are fully inserted. This is a relaxation of requirements, and is less restrictive. This change is acceptable, however, because the 92 day Frequency takes into consideration other information available to the operator in the control room, and performance of SR 3.1.4.1, which verifies that individual rod positions are within alignment limits every 12 hours and adds to the determination of OPERABILITY of the rods. In addition, not requiring fully inserted rods to be exercised is less restrictive than the CTS which does not have this exception. The intent of the exercise test is to provide assurance that the rod remains trippable (i.e., the rod is not stuck in the withdrawn position); thereby helping to assure that adequate Shutdown Margin is maintained. Not requiring fully inserted rods to be exercised is considered acceptable since with the rod in the fully inserted, it is not possible for the rod to be stuck in the withdrawn position. Therefore, elimination of the requirement to

exercise fully inserted rods has no impact on the ability to maintain adequate Shutdown Margin. This change is consistent with NUREG-1431.

L4 Not Used.

L5 With the MTC outside the limits provided in the COLR, CTS 3.1.3.3 requires the reactor be made subcritical by an amount greater than or equal to the potential reactivity insertion due to depressurization. Since no completion time is explicitly stated, this specification implies completion as soon as practical. (Although not directly applicable, CTS 3.0 requires hot shutdown within 8 hours. Without an explicit statement of completion time, the comparable completion time of 8 hours in CTS 3.0 is considered implicitly binding.) With MTC not within the lower limit, ITS 3.1.3 RA C.1 mandates being in MODE 4 with a completion time of 12 hours. This completion time is more than the implicit completion time for CTS 3.1.3.3. This change allows for a more controlled shutdown which reduces thermal stress on components and also reduces the chances for a plant transient which could challenge safety systems. The additional 4 hours to reach MODE 4 is considered reasonable, based on operating experience, to reach MODE 4 from full power conditions in an orderly manner and without challenging plant systems. The requirement to be in MODE 4 is more restrictive than the CTS 3.1.3.3 requirement to be subcritical by an amount greater than or equal to the potential reactivity insertion due to depressurization. This change is consistent with NUREG-1431.

L6 In the event the rod position indication requirements of CTS Table 4.1-1 items 9 and 10 are not satisfied, the CTS 3.10.1.5 actions associated with a misaligned rod are required to be taken within 2 hours. Rod position indication instruments do not necessarily relate directly to rod OPERABILITY (e.g. rods aligned within limits) or the ability to maintain rods within alignment limits. As such, it is overly restrictive to assume that rods are misaligned when rod position indication is inoperable. Therefore, ITS 3.1.7 is added to require the Analog Rod Position Indication (ARPI) System and the Demand Position Indication System to be OPERABLE in MODES 1 and 2 and provide alternate ACTIONS to determine rod position or reduce power to ≤ 50% RTP in the

Therefore, this change has no impact on the safe operation of the plant. Additionally, the report will still be required per 10 CFR 50.73 if results of the core reactivity re-evaluation (required by ITS 3.1.2 Required Action A.1) indicate plant operation in an unanalyzed condition. Deletion of the above reporting requirement also reduces the administrative burden on the plant and allows efforts to be concentrated on restoring core reactivity within limits. Therefore, the deletion of the special reporting requirement does not involve a significant reduction in a margin of safety.

L8 Change

Carolina Power & Light Company has evaluated the proposed Technical Specification change and has concluded that it does not involve a significant hazards consideration. Our conclusion is in accordance with the criteria set forth in 10 CFR 50.92. The bases for the conclusion that the proposed change does not involve a significant hazards consideration are discussed below.

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

   The proposed change does not involve any physical alteration of plant systems, structures or components or changes in parameters governing normal plant operation. The proposed change allows a 4 hour Surveillance Frequency for verification that individual rod positions are within the alignment limit when the rod position deviation alarm is inoperable. Control rod alignment limits are not initiators of any analyzed event. The 4 hour Frequency is considered adequate to detect a misalignment of control rods since control rod misalignments are infrequent and, if a control rod misalignment does occur, other indications of this condition are available. Other indications of control rod misalignment include changes in RCS temperature, AFD alarms, and QPTR alarms. At HBRSEP Unit No. 2, these indications of control rod misalignment would prompt a verification that individual rod positions are within the alignment limit. Therefore, the proposed Surveillance Frequency will provide assurance that any control rod misalignment will be detected such that the consequences of analyzed accidents are not impacted. Therefore, this change does not involve an increase in the probability or consequences of an accident previously evaluated.

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

   The proposed change does not involve any physical alteration of plant systems, structures or components or changes in parameters governing normal plant operation. The change involves only a Surveillance Frequency and introduces no new mode of plant operation or changes in the method of normal plant operation. Therefore, the possibility of a new or different kind of accident from any accident previously evaluated is not created.

3. Does this change involve a significant reduction in a margin of safety?

The proposed 4 hour Frequency for verifying individual control rod positions are within the alignment limit, when the rod position deviation monitor is inoperable, is based on the availability of other indications of control rod misalignment. The other indications of control rod misalignment include changes in RCS temperature, AFD alarms, and QPTR alarms. At HBRSEP Unit No. 2, these indications of control rod misalignment would prompt a verification that individual rod positions are within the alignment limit. In addition, industry operating experience has shown this frequency to be adequate for detecting control rod misalignments when the rod position deviation monitor is inoperable. Since the proposed change continues to provide adequate assurance that any control rod misalignment is detected in a timely manner, this change does not involve a significant reduction in the margin of safety.

3.1 REACTIVITY CONTROL SYSTEMS

3.1.~~8~~ 7 Rod Position Indication

[L6] LCO 3.1.~~8~~ 7 The ~~[Digital]~~ Analog Rod Position Indication (~~[D]~~ A RPI) System and the Demand Position Indication System shall be OPERABLE.

APPLICABILITY: MODES 1 and 2.

ACTIONS

----------NOTE----------
[L6] 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
[L6] A. One ~~[D]~~ A RPI 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.	Once per 8 hours
	OR		
	A.2	Reduce THERMAL POWER to ≤ 50% RTP.	8 hours
[L6] 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.	~~24~~ 4 hours
	OR		
			(continued)

CTS

3.1 REACTIVITY CONTROL SYSTEMS

3.1.10 (8) PHYSICS TESTS Exceptions – MODE 2

LCO 3.1.10 During the performance of PHYSICS TESTS, the requirements of

[3.1.3.1] LCO 3.1.4 (3) "Moderator Temperature Coefficient (MTC)";
[3.10.1.5] LCO 3.1.5 (4) "Rod Group Alignment Limits";
[3.10.1.2] LCO 3.1.6 (5) "Shutdown Bank Insertion Limits";
[3.10.1.3] LCO 3.1.7 (6) "Control Bank Insertion Limits"; and
[3.1.3.1] LCO 3.4.2, "RCS Minimum Temperature for Criticality"

may be suspended, provided:

[M22] a. RCS lowest loop average temperature is ≥ ~~[illegible]~~ °F; ~~and~~ 530

[3.10.1.6] b. SDM is ~~≥ 1.6% Δk/k~~ within limits provided in the COLR; and (2)

c. THERMAL POWER is < 5% RTP

APPLICABILITY: MODE 2 during PHYSICS TESTS.

TSTF-14

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
[M20] A. SDM not within limit.	A.1	Initiate boration to restore SDM to within limit.	15 minutes
	AND		
	A.2	Suspend PHYSICS TESTS exceptions.	1 hour
[M20] B. THERMAL POWER not within limit.	B.1	Open reactor trip breakers.	Immediately

(continued)

≤70% RTP, consistent with current licensing basis.

7 ITS SR 3.1.4.3 is modified to reflect a minimum T_{avg} of 540°F for verification of rod drop times, consistent with current licensing basis.

8 The word, "more," is changed to the word, "both," because plant design includes two shutdown banks.

9 Not Used.

10 ISTS Specification 3.1.8, Required Action C.1.2, is modified to provide two actions (ITS 3.1.7 Required Action C.1.2 and C.1.3) to address bank positions < 200 steps and bank positions ≥ 200 steps. This change is necessary to address the two different acceptance criteria associated with bank positions provided in ITS Specification 3.1.4 (for bank demand positions ≥ 200 steps, each rod shall be within 15 inches of its bank demand position; and for bank demand position < 200 steps, each rod shall be within 7.5 inches of the average of the individual rod positions in the bank) and the current licensing basis approved in HBRSEP Unit 2 Amendment No. 48.

11 ISTS Specification 3.1.6, "Control Bank Insertion Limits" are modified to be consistent with the current licensing basis.

12 ISTS Specification 3.1.9, "PHYSICS TEST Exceptions - MODE 1," is not adopted in the ITS. These physics tests are not performed during post-refueling startup testing. ISTS Specification 3.1.11, "SDM Test Exceptions," is not adopted in the ITS. The use of other rod worth measurement techniques will maintain the shutdown margin during the entire measurement process and still provide the necessary physics data verification. Since the N-1 measurement technique is no longer used, the SDM test exception is not necessary. Subsequent Specifications are renumbered accordingly.

13 ISTS SR 3.1.10.1 (ITS SR 3.1.8.1) is revised to require performance of the required CHANNEL OPERATIONAL TESTS within "7 days" prior to initiation of PHYSICS TESTS instead of within "12 hours" prior to initiation of PHYSICS TESTS. The current licensing basis reflected in

BASES

ACTIONS (continued)

A.2

more than offsets the increases in core F_Q and $F^N_{\Delta H}$ due to rod position

Reduction of THERMAL POWER to ≤ 50% RTP ~~puts the core into a condition where rod position is not significantly affecting core peaking factors (Ref. 3)~~ 36

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 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 ~~1~~ 4 ~~2~~ 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 ~~1~~ 4 ~~2~~ hours provides an acceptable period of time to verify the rod positions.

C.1.1 ~~and~~, C.1.2, and C.1.3 37

A

With one demand position indicator per bank inoperable, the rod positions can be determined by the RPI 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~~ within the allowed Completion Time of once every 8 hours is adequate. 37

that the position of each rod in the affected bank(s) is within 7.5 inches of the average of the individual rod positions in the affected bank(s) for bank positions < 200 steps and that the position of each rod in the affected bank(s) is within 15 inches of the bank demand position for bank positions ≥ 200 steps

37

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
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 provided in the COLR.	1 hour
	OR	
	D.1.2 Initiate boration to restore required SDM to within limit.	1 hour
	AND	
	D.2 Be in MODE 3.	6 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.4.1	Verify individual rod positions within alignment limit.	12 hours AND Once within 4 hours and every 4 hours thereafter when the rod position deviation monitor is inoperable

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.1.4.2	Verify rod freedom of movement (trippability) by moving each rod not fully inserted in the core ≥ 10 steps in either 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 beginning of decay of stationary gripper coil voltage to dashpot entry, with: a. T_{avg} ≥ 540°F; and b. All reactor coolant pumps operating.	Prior to reactor criticality after each removal of the reactor head

3.1 REACTIVITY CONTROL SYSTEMS

3.1.7 Rod Position Indication

LCO 3.1.7 The Analog Rod Position Indication (ARPI) 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 ARPI 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.	Once per 8 hours
	OR		
	A.2	Reduce THERMAL POWER to ≤ 50% RTP.	8 hours
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.	4 hours
	OR		
			(continued)

BASES

ACTIONS (continued)

A.2

Reduction of THERMAL POWER to ≤ 50% RTP more than offsets the increase in core F_Q and $F^N_{\Delta H}$ due to rod position.

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 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 4 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 4 hours provides an acceptable period of time to verify the rod positions.

C.1.1, C.1.2, and C.1.3

With one demand position indicator per bank inoperable, the rod positions can be determined by the ARPI System. Since normal power operation does not require excessive movement of rods, verification by administrative means that the rod position indicators are OPERABLE, that the position of each rod in the affected bank(s) is within 7.5 inches of the average of the individual rod positions in the affected bank(s), for bank positions < 200 steps and that the position of each rod in the affected bank(s) is within 15 inches of the bank demand position for bank positions ≥ 200 steps within the allowed Completion Time of once every 8 hours is adequate.

(continued)

SUPPLEMENT 8
CONVERSION PACKAGE SECTION 3.2
PAGE INSERTION INSTRUCTIONS

Remove and insert the following pages into Enclosure 10 to Serial: RNP-RA/96-0141.

	Remove Page	Insert Page
a.	Part 1, "Markup of Current Technical Specifications (CTS)" NA	
b.	Part 2, "Discussion of Changes (DOCs) for CTS Markup" NA	
c.	Part 3, " No Significant Hazards Consideration (NSHC), And Basis for Categorical Exclusion from 10 CFR 51.22 NA	
d.	Part 4, "Markup of NUREG-4131, Revision 1, Standard Technical Specifications-Westinghouse Plants, (ISTS)" NA	
e.	Part 5, "Justification of Differences (JFDs) to ISTS" NA	
f.	Part 6, "Markup of ISTS Bases" NA	
g.	Part 7, "Justification for Differences (JFDs) to ISTS Bases" NA	
h.	Part 8, "Proposed HBRSEP, Unit No. 2 ITS" NA	
i.	Part 9. "Proposed Bases to HBRSEP, Unit No. 2 ITS Bases" B 3.2-30	B 3.2-30
j.	Part 10. "ISTS Generic Changes" NA	

BASES

ACTIONS

A.4 (continued)

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. Should Required Actions A.1, A.2, and A.3 result in restoration of QPTR within its limit, LCO 3.2.4 is satisfied, and Condition A can be exited prior to completion of Required Action A.4.

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 normalized to eliminate the indicated tilt prior to increasing THERMAL POWER to above the limit of Required Action A.1 and A.2. This is done to detect any subsequent significant changes in QPTR.

Required Action A.5 is modified by a Note that states that the indicated tilt is not eliminated 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.

A.6

Once the excore detectors are normalized to eliminate the indicated tilt (i.e., Required Action A.5 is performed), it

(continued)

SUPPLEMENT 8
CONVERSION PACKAGE SECTION 3.3
PAGE INSERTION INSTRUCTIONS

Remove and insert the following pages into Enclosure 11 to Serial: RNP-RA/96-0141.

	Remove Page	Insert Page
a.	Part 1, "Markup of Current Technical Specifications (CTS)"	
	2.3-1 (3.3.1) 2.3-3 (3.3.1)	2.3-1 (3.3.1) 2.3-3 (3.3.1)
	3.5-13b (3.3.1)	3.5-13b (3.3.1)
	4.1-7 (3.3.1) 4.1-9 (3.3.1)	4.1-7 (3.3.1) 4.1-9 (3.3.1)
	3.5-10 (3.3.2)	3.5-10 (3.3.2)
	3.5-19a (3.3.3)	3.5-19a (3.3.3)
	3.5-15a (3.3.5) (sheet 2)	3.5-15a (3.3.5) (sheet 2)
	3.4-6 (3.3.8)	3.4-6 (3.3.8)
b.	Part 2, "Discussion of Changes (DOCs) for CTS Markup"	
	8, 9	8, 9
	-	9a
	29	29
	-	34a
	47, 48	47, 48
c.	Part 3, "No Significant Hazards Consideration (NSHC), And Basis for Categorical Exclusion from 10 CFR 51.22"	
	32, 33	32, 33
d.	Part 4, "Markup of NUREG-1431, Revision 1, Standard Technical Specifications Westinghouse Plants, (ISTS)"	
	3.3-11	3.3-11
	-	Insert 3.3-11A (page 3.3-11A)
	3.3-15, 3.3-16, 3.3-17, 3.3-18, 3.3-19	3.3-15, 3.3-16, 3.3-17, 3.3-18, 3.3-19
	ITS Insert 3.3.1-2 (page 3.3-19a)	ITS Insert 3.3.1-2 (page 3.3-19a)
	3.3-20, 3.3-21, 3.3-22, 3.3-32	3.3-20, 3.3-21, 3.3-22, 3.3-32
	3.3-33, 3.3-34, 3.3-35, 3.3-36, 3.3-37	3.3-33, 3.3-34, 3.3-35, 3.3-36, 3.3-37
	3.3-38, 3.3-39	3.3-38, 3.3-39
	ITS Insert 3.3.2-4 (page 3.3-39a)	ITS Insert 3.3.2-4 (page 3.3-39a)
	3.3-47, 3.3-49	3.3-47, 3.3-49
	ITS Insert 3.3.8-1 (pages 2 & 4)	ITS Insert 3.3.8-1 (pages 2 & 4)

SUPPLEMENT 8
CONVERSION PACKAGE SECTION 3.3
PAGE INSERTION INSTRUCTIONS

Remove and insert the following pages into Enclosure 11 to Serial: RNP-RA/96-0141.

Remove Page	Insert Page
e. Part 5, "Justification of Differences (JFDs) to ISTS"	
4	4
-	4a
9, 15	9, 15
-	16
f. Part 6, "Markup of ISTS Bases"	
B 3.3-2, B 3.3-4	B 3.3-2, B 3.3-4
ITS Insert B 3.3.1-1 (page B 3.3-4a)	ITS Insert B 3.3.1-1 (page B 3.3-4a)
B 3.3-5, B 3.3-8, B 3.3-9, B 3.3-14	B 3.3-5, B 3.3-8, B 3.3-9, B 3.3-14
B 3.3-35, B 3.3-36, B 3.3-37, B 3.3-53	B 3.3-35, B 3.3-36, B 3.3-37, B 3.3-53
-	Insert B 3.3-53A (page B 3.3-53A)
B 3.3-54, B 3.3-56, B 3.3-60	B 3.3-54, B 3.3-56, B 3.3-60
-	Insert B 3.3-60A (page B 3.3-60A)
B 3.3-61, B 3.3-63	B 3.3-61, B 3.3-63
-	ITS Insert B 3.3.2-3, B 3.3-70a
B 3.3-64, B 3.3-69, B 3.3-73	B 3.3-64, B 3.3-69, B 3.3-73
B 3.3-85, B 3.3-106	B 3.3-85, B 3.3-106
-	Insert B 3.3-106A (page B 3.3-106A)
B 3.3-107	B 3.3-107
B 3.3-110	B 3.3-110
-	Insert B 3.3-110A (page B 3.3-110A)
ITS Insert B 3.3.2-13 (no page no)	ITS Insert B 3.3.2-13 (page B 3.3-114a)
ITS Insert B 3.3.2-13a (page B 3.3-114b)	ITS Insert B 3.3.2-13a (page B 3.3-114b)
B 3.3-116, B 3.3-118, B 3.3-120	B 3.3-116, B 3.3-118, B 3.3-120
Insert B 3.3.2-17 (page B 3.3-120A)	Insert B 3.3.2-17 (page B 3.3-120A)
ITS Insert B 3.3.5-2 (page B 3.3-144A)	ITS Insert B 3.3.5-2 (page B 3.3-144A)
B 3.3-147, B 3.3-149	B 3.3-147, B 3.3-149
ITS Insert B 3.3.5-6 & B 3.3.5-6A (page B 3.3-149A)	ITS Insert B 3.3.5-6 & B 3.3.5-6A (page B 3.3-149A)
B 3.3-152	B 3.3-152
ITS Insert B 3.3.8 (page 1 through 11)	ITS Insert B 3.3.8 (page 1 through 12)

SUPPLEMENT 8
CONVERSION PACKAGE SECTION 3.3
PAGE INSERTION INSTRUCTIONS

Remove and insert the following pages into Enclosure 11 to Serial: RNP-RA/96-0141.

	Remove Page	Insert Page
g.	Part 7, "Justification for Differences (JFDs) to ISTS Bases"	
	1	1
	-	1a
	3	3
h.	Part 8, "Proposed HBRSEP, Unit No.2 ITS"	
	3.3-9, 3.3-13	3.3-9, 3.3-13
	3.3-14, 3.3-15, 3.3-16, 3.3-17	3.3-14, 3.3-15, 3.3-16, 3.3-17
	3.3-18, 3.3-19, 3.3-25, 3.3-26, 3.3-27	3.3-18, 3.3-19, 3.3-25, 3.3-26, 3.3-27
	3.3-28, 3.3-37, 3.3-38, 3.3-48, 3.3-50	3.3-28, 3.3-37, 3.3-38, 3.3-48, 3.3-50
i.	Part 9, "Proposed Bases to HBRSEP, Unit No. 2 ITS"	
	B 3.3-2, B 3.3-3, B 3.3-4	B 3.3-2,B 3.3-3, B 3.3-4
	B 3.3-5, B 3.3-6, B 3.3-7	B 3.3-5, B 3.3-6, B 3.3-7
	B 3.3-8, B 3.3-9, B 3.3-10, B 3.3-13	B 3.3-8, B 3.3-9, B 3.3-10, B 3.3-13
	B 3.3-32, B 3.3-33, B 3.3-34	B 3.3-32, B 3.3-33, B 3.3-34
	B 3.3-44 through B 3.3-48	B 3.3-44 through B 3.3-48
	B 3.3-49, B 3.3-50, B 3.3-50a, B 3.3-51	B 3.3-49, B 3.3-50, B 3.3-51
	B 3.3-52, B 3.3-53, B 3.3-54	B 3.3-52, B 3.3-53, B 3.3-54
	-	B 3.3-54a
	B 3.3-56, B 3.3-57	B 3.3-56, B 3.3-57
	-	B 3.3-57a
	B 3.3-58, B 3.3-61	B 3.3-58, B 3.3-61
	-	B 3.3-61a
	B 3.3-64, B 3.3-79	B 3.3-64, B 3.3-79
	-	B 3.3-79a
	B 3.3-80	B 3.3-80
	-	B 3.3-80a
	B 3.3-82	B 3.3-82
	-	B 3.3-82a
	B 3.3-83, B 3.3-84, B 3.3-86, B 3.3-87	B 3.3-83, B 3.3-84, B 3.3-86, B 3.3-87
	B 3.3-88, B 3.3-113, B 3.3-116	B 3.3-88, B 3.3-113, B 3.3-116
	B 3.3-117	B 3.3-117
	-	B 3.3-117a
	B 3.3-119, B 3.3-131, B 3.3-132	B 3.3-119, B 3.3-131, B 3.3-132

SUPPLEMENT 8
CONVERSION PACKAGE SECTION 3.3
PAGE INSERTION INSTRUCTIONS

Remove and insert the following pages into Enclosure 11 to Serial: RNP-RA/96-0141.

Remove Page	Insert Page
i. Part 9, "Proposed Bases to HBRSEP, Unit No. 2 ITS" (continued)	
B 3.3-133, B 3.3-134, B 3.3-135	B 3.3-133, B 3.3-134, B 3.3-135
B 3.3-136, B 3.3-137,B 3.3-138	B 3.3-136, B 3.3-137, B 3.3-138
B 3.3-139	B 3.3-139
-	B 3.3-140, B 3.3-141
j. Part 10, "ISTS Generic Changes"	
NA	

ITS

A1

2.3 LIMITING SAFETY SYSTEM SETTINGS, PROTECTIVE INSTRUMENTATION

Applicability

Applies to trip settings for instruments monitoring reactor power and reactor coolant pressure, temperature, and flow and pressurizer level.

Objective

To provide for automatic protection action in the event that the principal process variables approach a safety limit.

Specification

L1 M1

[LCO 3.3.1] 2.3.1 Protective instrumentation ~~settings for reactor trip shall be~~ OPERABLE as follows:

Add Note (1) to Table 3.3.1-1:
A channel is OPERABLE with a Nominal Trip Setpoint value found outside its calibration tolerance band provided the Trip Setpoint value is conservative with respect to its associated Allowable Value and the channel is re-adjusted to within the established calibration tolerance band of the Nominal Trip Setpoint.

2.3.1.1 Start-up protection

[T3.3.1-1 (2.b)] a. High flux, power range ~~(low setpoint)~~ ~~≤ 25%~~ 24 of rated power.

2.3.1.2 Core protection

[T3.3.1-1 (2.a)] a. High flux, power range (high setpoint) ~~≤ 109%~~ 108 of rated power

[T3.3.1-1 (7.b)] b. High pressurizer pressure ~~≤ 2385~~ 2376 psig.

[T3.3.1-1 (7.a)] c. Low pressurizer pressure ~~≥ 1835~~ 1844 psig.

M1

[T3.3.1-1 (5)] d. Overtemperature Δ T

L1

[NOTE 1] The OTΔT Function Allowable Value shall not exceed the following Nominal Trip Setpoint by more than 2.96% of ΔT span.

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

M20

Add Nominal Trip Setpoints

Intermediate Range Neutron Flux	25% thermal power
Source Range Neutron Flux	1.0E5 cps
Steam Generator water level low	30%
Coincident with Steam Flow/Feedwater Flow Mismatch	6.4E5 lbm/hr
Turbine Trip low autostop oil pressure	45 psig

ITS

[T3.3.1-1 (5)] [NOTE 1]

(3) For each percent that the magnitude of $(q_t - q_b)$ exceeds -17% in the negative direction, the ΔT trip setpoint shall be automatically reduced by ~~2.4% of the value of ΔT at rated power (2300 Mwt)~~. 2.4 $(q_b - q_T)$ - 17 percent (A1) (A2)

[T3.3.1-1 (6)] [NOTE 2]

e. Overpower Δ T

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

The OPΔT Function Allowable Value shall not exceed the following (Nominal) Trip Setpoint by more than 3.17% of ΔT span. (L1)

where:

ΔT_o = Indicated ΔT at rated thermal power, °F;

T = Average temperature, °F;

T′ = 575.4°F Reference T_{avg} rated thermal power;

K_4 = ~~1.07~~; ≤ 1.06 (M1) (L2)

K_5 = 0.0 for decreasing average temperature, 0.02 sec/°F for increasing average temperature;

K_6 = 0.00277 for T > T′ and 0 for T ≤ T′;

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

$\frac{\tau_3 S}{1 + \tau_3 S}$ = The function generated by the rate-lag controller for T_{avg} dynamic compensation;

τ_3 = Time constant utilized in the rate-lag controller for T_{avg}; τ_3 ~~≤ 10~~ ≥ 9 seconds; (LA1) (L2)

f(ΔI) = As defined in d. above (99.26) (M1)

[T3.3.1-1 (9)] f. Low reactor coolant loop flow ≥ ~~90%~~ of normal indicated flow.

[T3.3.1-1 (12)] g. Low reactor coolant pump frequency ≥ ~~57.5~~ 58.2 Hz. (a. Single loop b. Two loops) (A3)

[T3.3.1-1 (11)] h. Undervoltage ≥ ~~70% of normal voltage~~ 3120

2.3.1.3 Other Reactor Trips

[T3.3.1-1 (8)] a. High pressurizer water level ≤ ~~92%~~ 91 of span. (M1)

[T3.3.1-1 (13)] b. Low-low steam generator water level ≥ ~~14%~~ 16 of narrow range instrument span.

ITS

TABLE 3.5-2 (Continued)

REACTOR TRIP INSTRUMENTATION LIMITING OPERATING CONDITIONS

TABLE NOTATIONS

(a) * With ~~the reactor trip breakers closed~~ rod control system capable of rod withdrawal or one or more rods not fully inserted. (A1) (L35)

(b) ** Below the P-10 (Low Setpoint Power Range Neutron Flux Interlock) setpoint.

(d) *** Below the P-6 (Intermediate Range Neutron Flux Interlock) setpoint.

(h) **** Above the ~~P-10 (Low Setpoint Power Range Neutron Flux Interlock) setpoint or~~ P-7 (Turbine First Stage Pressure Interlock) setpoint and below the P-8 (Low Setpoint Power Range Neutron Flux Interlock) setpoint. (L5)

(f) ***** Above the ~~P-10 (Low Setpoint Power Range Neutron Flux Interlock) setpoint or~~ P-7 (Turbine First Stage Pressure Interlock) setpoint. (A30)

Add Note (c) (A31)

ACTION STATEMENTS

Add Note (e)

[ACTION B] ~~ACTION 1~~ With the number of OPERABLE channels one less than the Minimum Channels OPERABLE requirement, restore the inoperable channel to OPERABLE status within 48 hours, or be in the ~~Hot Shutdown Condition~~ Mode 3 within ~~the next 6~~ hours and open RTBs in 55 hours. (L6)

[ACTION D] ~~ACTION 2~~ With the number of OPERABLE channels one less than the Total Number of Channels, Startup and/or Power Operation may proceed provided the following Conditions are satisfied: (L7)

Add RA D.2.2 "NOTE"

[ACTION E] a. The inoperable channel is placed in the tripped condition within ~~1~~ 6 hour. (L8)

[ACTION D] b. Either, thermal power is restricted to less than or equal to 75% of rated power ~~and the Power Range Neutron Flux trip setpoint is reduced to less than or equal to 85% of rated power within 4 hours; or, the Quadrant Power Tilt Ratio is monitored within 12 hours and every 12 hours thereafter, using the movable incore detectors to confirm that the normalized symmetric power distribution is consistent with the indicated Quadrant Power Tilt Ratio~~ be in MODE 3 in 12 hours (M6)

[ACTION E]

~~ACTION 3~~ With the number of channels OPERABLE one less than the Minimum Channels OPERABLE requirement and with the thermal power level:

[ACTION H] a. Below the P-6 (Intermediate Range Neutron Flux Interlock) setpoints, restore the inoperable channel to OPERABLE status prior to increasing thermal power above the P-6 setpoint.

[ACTION F] b. Above the P-6 (Intermediate Range Neutron Flux Interlock) setpoint but below 10% of rated power ~~restore the inoperable channel to OPERABLE status prior to increasing thermal power above 10% of rated power.~~ (M7)

Reduce power to < P6 in 2 hours or increase power to > P10 in 2 hours. (L36)

With the number of channels OPERABLE one or two less than the Minimum Channels OPERABLE (L38)

ITS

TABLE 4.1-1 (Continued)

	Channel Description	Check	Calibrate	Test	Remarks
	21. Containment Sump Level	N.A.	R	N.A.	See 3.4.15 M17
[T3.3.1-1(15)]	22. Turbine Trip Logic**	N.A.	N.A. SR3.3.1.10	~~R~~ SR 3.3.1.15	
	23. Accumulator Level and Pressure	S	R	N.A.	LA4
	24. Steam Generator Pressure	S	R	M	See ITS 3.3.2
[T3.3.1-1(17.e)]	25. Turbine ~~First Stage~~ Impulse Pressure	~~S~~ SR3.3.1.1	~~R~~ SR3.3.1.10	~~M~~ SR3.3.1.13	L17
	26. ~~DELETED~~				
[T3.3.1-1(20)]	27. Logic Channel Testing Automatic Trip	N.A.	N.A.	M(1) S/U(2) SR 3.3.1.5	(1) Applicability MODES 1,2,3,4,5 During hot shutdown and power operations. ~~When periods of reactor cold shutdown and refueling extend this interval beyond one month, this test shall be performed prior to startup.~~ M18 M19
					~~(2) Logic channel testing for nuclear source range channels shall only be required prior to each reactor startup, if not performed within the previous seven (7) days.~~ L18
	28. ~~DELETED~~				
[T3.3.1-1(12)]	29. ~~SR~~ Frequency RCPs	N.A.	~~SR~~ SR3.3.1.10	~~SR~~ SR3.3.1.14	

on a STAGGERED TEST BASIS

Add Note (j) to Table 3.3.1-1 A41

[T3.3.1-1(15)]** Stop valve closure or low EH fluid pressure.

[T 3.3.1-1 (17.a – d)] Add SR 3.3.1.11 and SR 3.3.1.13 for RPS interlocks P-6, P-8, P-10 and SR 3.3.1.13 and SR 3.3.1.14 for RPS interlock P-7 M14

Specification 3.3.1 A1

Supplement 8

Amendment No. ~~83~~, ~~106~~, ~~122~~, ~~127~~, 133

TABLE 4.1-1 (Continued)

MINIMUM FREQUENCIES FOR CHECKS, CALIBRATIONS AND TEST OF INSTRUMENT CHANNELS

ITS

	Channel Description	Check	Calibrate	Test	Remarks
	b. Main Vent Stack				See 3.3.3
	High Range	D	R	Q	
	Mid Range	D	R	Q	
	c. Spent Fuel Pit Lower Level				M21
	High Range	D	R	Q	
[T3.3.1-1(14)] 39.	Steam/Feedwater Flow Mismatch	~~N.A.~~ SR 3.3.1.1	~~R~~ SR 3.3.1.10	~~R~~ SR 3.3.1.7	L16
[T3.3.1-1(14)] 40.	Low Steam Generator Water Level	~~N.A.~~ SR 3.3.1.1	~~R~~ SR 3.3.1.10	~~R~~ SR 3.3.1.7	
41.	CV Level (Wide Range)+	M	R	R	See 3.3.3
42.	CV Pressure (Wide Range)++	M	R	R	
43.	CV Hydrogen Monitor+++	M	R	R	
44.	CV High Range Radiation Monitor++++	M	R#	R	
45.	RCS High Point Vents	N.A.	N.A.	R	See Relocated Specifications
[T3.3.1-1(1)] 46.	Manual Reactor Trip	N.A.	N.A.	~~R(1)~~ SR 3.3.1.14	A7
[T3.3.1-1(1,18,19)] 47.	Reactor Trip Bypass Breakers	N.A.	N.A.	~~M(3), R(4)~~ SR 3.3.1.4 SR 3.3.1.14	L20

~~(1) The manual reactor trip operational test shall verify the independent operability of the manual shunt trip circuit and the manual UV trip circuit on the reactor trip breakers. The test shall also verify the operability of the UV trip circuit on the bypass breakers.~~

~~(3) Remote manual UV trip required only when placing the bypass breaker in service.~~

~~(4) Perform UV trip from protection system.~~

Add Note to SR 3.3.1.5 — M53

Specification 3.3.1 — A1

Supplement 8

A1

ITS

TABLE 3.5-1

ENGINEERED SAFETY FEATURE SYSTEM INITIATION INSTRUMENT SETTING LIMITS

	NO.	FUNCTIONAL UNIT	CHANNEL ACTION	SETTING LIMIT
[T3.3.2-1(1.c)]	1.	High Containment Pressure (HI Level)	Safety Injection*	≤ ~~5~~ 4 psig
[T3.3.2-1(2.c)]	2.	High Containment Pressure (HI-HI Level)	a. Containment Spray** b. Steam Line Isolation	≤ ~~25~~ 20 psig
[T3.3.2-1(1.d)]	3.	Pressurizer Low Pressure	Safety Injection*	≥ ~~1700~~ 1715 psig
[T3.3.2-1(1.e)]	4.	High Differential Pressure Between any Steam Line and the Steam Line Header	Safety Injection*	≤ ~~150~~ 100 psi
[T3.3.2-1(4.d,4.e)]	5.	High Steam Flow in 2/3 Steam Lines***	a. Safety Injection* b. Steam Line Isolation	≤ ~~40~~ 37.25% (at zero load) of full steam flow ≤ ~~40~~ 37.25% (at 20% load) of full steam flow ≤ ~~110~~ 109% (at full load) of full steam flow
		Coincident with Low T_{avg} or Low Steam Line Pressure		≤ ~~541~~ 543 °F T_{avg} ≥ ~~500~~ 614 psig steam line pressure
	6.	Loss of Power		
		a. 480V Emerg. Bus Undervoltage (Loss of Voltage) Time Delay	Trip Normal Supply Breaker	328 Volts ± 10% ≤ 1 sec when voltage is reduced to zero

M1

Add Note (3) to Table 3.3.3-1, The Nominal Trip Setpoint is as stated unless reduced as required by LCO 3.2.1 Required Action A.2.3. M1

See 3.3.5

Add Note (1) to Table 3.3.2-1: A channel is OPERABLE with an actual Trip Setpoint value found outside its calibration tolerance band provided the Trip Setpoint value is conservative with respect to its associated Allowable Value and the channel is re-adjusted to within the established calibration tolerance band of the Nominal Trip Setpoint. M1

Add Note (2) to Table 3.3.1-1, The Nominal Trip Setpoint is as stated unless reduced as required by One or more of the following requirements: LCO 3.2.1 Required Action A.2.2; LCO 3.2.2 Required Action A.1.2.2; or LCO 3.7.1 Required Action B.2 M1

Specification 3.3.3

A1

TABLE 3.5-5 (Continued)

ITS

INSTRUMENTATION TO FOLLOW THE COURSE OF AN ACCIDENT

TABLE NOTATION

With one channel inoperable, restore the channel to OPERABLE status within 30 days — L.22

[ACTION A] [ACTION C] [ACTION B] [ACTION H] initiate action per 5.6.6

Note 4: With the number of OPERABLE Channels ~~less than~~ (two) required by the Minimum Channels OPERABLE requirement, restore the inoperable Channel(s) to OPERABLE status within 7 days or, prepare and submit a Special Report to the NRC within the following 14 days detailing the cause of the inoperable Channel(s), the action being taken to restore the Channel(s) to operable status, the estimated date for completion of repairs, and any compensatory action being taken while the Channel(s) is inoperable. — See 5.6.6

[ACTION A] [ACTION B] initiate action per 5.6.6

Note 5: If one channel is inoperable, restore the channel to operable status within 30 days or, prepare and submit a special report to the NRC within the following 14 days detailing the cause(s) of the inoperable channels, the actions being taken to restore the channel to operable status, the estimated date for completion of the repairs, and the compensatory action being taken while the channel is inoperable. — See 5.6.6

If both channels become inoperable ~~and a pre-planned alternate method of monitoring is available,~~ then restore at least one channel to operable status within 7 days or prepare and submit a special report to the NRC within the following 14 days detailing the cause(s) of the inoperable channels, the action being taken to restore at least one channel to operable status, the estimated date for completion of the repairs, and a description of the alternate method of monitoring the affected parameter while both channels are inoperable. — LA6, See 5.6.6

~~If a pre-planned alternate method of monitoring the affected parameter is not available and implemented with both channels inoperable, then restore at least one channel to an operable status within 7 days or be in Hot Shutdown within 6 hours and ≤ 350°F within the following 30 hours.~~ — L44

[ACTION C] [ACTION H]

[ACTION E] [ACTION G]

Note 6: With both channels inoperable, restore at least one channel to an operable status within ~~14 days~~ (72 hours) or be in ~~Hot Shutdown~~ (MODE 3) within 6 hours (6) and ~~≤ 200°F~~ (MODE 4) within the following ~~30~~ (6) hours. — L24, M31, L24

Add Functions & Requirements:
- SG Pressure
- Cont. Spray Additive Tank Level
- Cont. Isolation Valve Position Indication
- SG Level
- Power Range Neutron Flux
- Source Range Neutron Flux
- RCS Pressure
- RCS Hot Leg Temperature
- RCS Cold Leg Temperature
- RWST Level
- CST Level

M32

A1

ITS

TABLE 3.5-3 (Continued)

ENGINEERED SAFETY FEATURES INSTRUMENTATION LIMITING OPERATING CONDITIONS

TABLE NOTATIONS

Above Low Pressure SI Block Permit interlock.
Trip function may be blocked below Low T_{avg} Interlock setpoint.
The reactor may remain critical below the Power Operating conditions with this feature inhibited for the purpose of starting reactor coolant pumps.

[Applicability Note]

See 3.3.2

ACTION 11 With the number of OPERABLE channels one less than the Minimum Channels OPERABLE requirement, restore the inoperable channel to OPERABLE status within 48 hours or be in at least the Hot Shutdown Condition within the next 8 hours and the Cold Shutdown Condition within the following 30 hours.

ACTION 12 With the number of OPERABLE channels one less than the Total Number of Channels. Power Operation may proceed until performance of the next required operational test provided the inoperable channel is placed into the tripped condition within 1 hour.

ACTION 13 With the number of OPERABLE channels one less than the Minimum Channels OPERABLE requirement, restore the inoperable channel to OPERABLE status within 1 hour or be in at least the Hot Shutdown Condition within the next 8 hours and the Cold Shutdown Condition within the following 30 hours.

L29

ACTION 14 With the number of OPERABLE channels per bus one less than the Total Number of Channels; place the inoperable channel into the ~~blocked~~ tripped condition within 1 hour, ~~and restore the inoperable channel to OPERABLE status within 48 hours or be in at least the Hot Shutdown Condition within the next 8 hours and the Cold Shutdown Condition within the following 30 hours.~~

[ACTION B]

[ACTION D]

6

Degraded voltage function

or enter applicable condition(s) and RA(s) for the associated DG made inoperable by LOP DG start instrumentation immediately

Add ACTION C

M37

A1

TABLE 3.4-2

AUXILIARY FEEDWATER SYSTEM AUTOMATIC INITIATION SETPOINTS

ITS	FUNCTIONAL UNIT	SETTING LIMIT
	AUXILIARY FEEDWATER	
[T3.3.8-1(1)]	a. Steam Generator Water Level-low-low	≥ 16% of narrow range instrument span each steam generator (M1)
[T3.3.8-1(4)]	b. Undervoltage - 4KV Busses 1 & 4	≥ 70% of 4KV Busses 1 & 4 Normal Voltage (3120)
[T3.3.8-1(2)]	c. S.I.	See Table 3.5-3, Item No. 1 and Table 3.5-1 (3.3.2-1, Function 1)
[T3.3.8-1(3)]	d. Station Blackout	See Table 3.5-1, Item No. 6 (328 V ± 10% with ≤ 1 sec. time delay)

Add T 3.3.8-1 "Allowable Values" (M12)

Add Note (1) to Table 3.3.8-1: (M1)

A channel is OPERABLE with an actual Trip Setpoint value found outside its calibration tolerance band provided the Trip Setpoint value is conservative with respect to its associated Allowable Value and the channel is re-adjusted to within the established calibration tolerance band of the Nominal Trip Setpoint.

A40 The Table Notation of CTS Table 3.5-2, Reactor Trip Instrumentation Limiting Operating Conditions, includes ACTION 7. CTS Table 3.5-2 does not include any requirements to enter ACTION 7 in the event of an instrumentation function inoperability. Therefore, CTS Table 3.5-2 ACTION 7 is deleted from the Technical Specifications as an administrative change and has no adverse impact on safety.

A41 CTS Table 3.5-2 Item 4 permits the source range neutron detector channels to be inoperable above the P-6 (Intermediate Range Neutron Flux) setpoint. Logic channel testing required by CTS Table 4.1-1 Item 27 is not required by CTS for instrumentatin not required to be OPERABLE (i.e., the source range logic inputs). Therefore, the addition of Note (j) to Table 3.3.1-1, which only requires the automatic trip logic inputs from the source range neutron detector channels to be operable below the P-6 interlock is an administrative change and has no impact on safety.

TECHNICAL CHANGES - MORE RESTRICTIVE

M1 The CTS is revised to adopt the actual nominal trip setpoints that are used. These actual setpoints are more conservative than the CTS trip setpoint limits. The Trip Setpoints used in the bistables are based on the analytical limits. The selection of these Trip Setpoints is such that adequate protection is provided when sensor and processing time delays accounted for in setpoint calculations and accident analyses are taken into account. To allow for calibration tolerances, instrumentation uncertainties, instrument drift, and severe environment errors for those channels that must function in harsh environments as defined by 10 CFR 50.49, the Nominal Trip Setpoints and Allowable Values specified in the ITS instrumentation Tables are conservatively adjusted with respect to the analytical limits. The addition of Allowable Values for these same instruments is addressed in Discussion of Change M12 for ITS 3.3. In addition, in the Tables for ITS 3.3.1 (RPS Instrumentation) (CTS 2.3.1), ITS 3.3.2 (ESFAS Instrumentation) (CTS Table 3.5-1), and ITS 3.3.8 (AFW System Instrumentation) (CTS Table 3.4-2), the terms "settings" and "Setting Limits" are modified to "Nominal Trip Setpoint", the inequality signs associated with the "settings" and "Setting Limits" are removed, and a Note is added clarifying channel OPERABILITY relative to actual trip settings. These changes are being made for consistency with the CP&L setpoint methodology. The setpoint calculations performed for each of the affected setpoints using the CP&L setpoint methodology demonstrate that a channel is OPERABLE if its actual trip setting, between CHANNEL CALIBRATIONS, exceeds the associated Nominal Trip Setpoint but is within the Allowable Value provided the channel is re-adjusted to within the established "as left" calibration tolerance band. The setpoint calculations also demonstrate that if a channel trip setting is within the established "as found" calibration tolerance band associated with the Trip Setpoint, no adjustment of the channel's calibration is necessary to ensure the channel is maintained OPERABLE for the length of the CHANNEL CALIBRATION interval. Therefore, the revised Trip Setpoints are actually "nominal" values rather than "absolute" values. In addition, since these Trip Setpoints are "nominal" values, the inequality signs associated with the Trip Setpoints are not necessary to ensure that the assumptions of the setpoint calculations and OPERABILITY of the associated instrumentation channels are maintained provided the trip settings are within the specified Allowable Values. Note (2) was added to permit adjustment of the Nominal Trip Setpoints when directed by Required Actions. The use of more conservative parameters is considered to be more restrictive, and has no adverse impact on safety.

M2 CTS Specification 3.5.1.5 and Table 3.5-2 ACTION 4 require that certain corrective actions be taken. ITS Specification 3.3.1 ACTIONS A and I, and ITS Specification 3.3.2 ACTION A, require that these corrective actions be taken "immediately." Since no time constraint currently

exists, this change is more restrictive, and has no adverse impact on safety.

ITS 3.3.1 Action A applies to RPS protection Functions. Condition A addresses the situation where one or more required channels for one or more Functions are inoperable at the same time. This action requires immediate entry into the appropriate Condition specified in ITS Table 3.3.1-1. Immediate entry into the specified Condition assures additional ITS specified Required Actions are implemented as required.

ITS 3.3.1 Action I applies to one inoperable Source Range Neutron Flux trip channel when in MODE 2, below the P-6 setpoint. With the unit in this Condition, below P-6, the NIS source range performs the monitoring and protection functions. With one of the two channels inoperable, operations involving positive reactivity additions shall be suspended immediately. This will preclude any power escalation. With only one source range channel OPERABLE, core protection is severely reduced and any actions that add positive reactivity to the core must be suspended immediately.

ITS 3.3.2 Action A applies to ESFAS protection Functions. Action A addresses the situation where one or more required channels for one or more Functions are inoperable at the same time. This action requires immediate entry into the appropriate Condition specified in ITS Table 3.3.2-1. Immediate entry into the specified Condition assures additional ITS specified Required Actions are implemented as required.

capability of the motor driven AFW pumps from the SG Water Level-Low-Low Function is maintained in the event of a single failure.

M52 CTS Table 4.1-1 item 18 requires a CHANNEL CHECK of the containment pressure instrumentation to be performed once per 24 hours. This instrumentation is addressed in ITS Table 3.3.2-1 by Functions 1.c, 2.c, 3.a(3), 3.b(3), and 4.c. ITS SR 3.3.2.1, which applies to these Functions, requires a CHANNEL CHECK to be performed once per 12 hours. The purpose of a CHANNEL CHECK is to detect gross channel failure between each CHANNEL CALIBRATION. This change reduces the Surveillance interval from once per 24 hours to once per 12 hours and represents an additional restriction on plant operation necessary to achieve consistency with other instrumentation CHANNEL CHECK requirements and NUREG-1431, Revision 1.

M53 The CTS is modified to add a Note to ITS SR 3.3.1.5. An explicit provision in CTS that is comparable to the Note to ITS SR 3.3.1.5. The frequency for logic channel testing for the source range channel inputs is identified in Note 2 to CTS Table 4.1-1, Item 27. Note 2 to CTS Table 4.1-1, Item 27 requires logic channel testing from the source range channel inputs to be performed prior to startup if not performed within the previous 7 days. SR 3.3.1.5 requires performance of an ACTUATION LOGIC TEST at a Frequency of 31 days on a STAGGERED TEST BASIS. The Note to SR 3.3.1.5 states that the source range channel inputs into the logic does not have to be performed prior to entry into MODE 3 from MODE 2 until 4 hours after entry into MODE 3. The requirement to perform SR 3.3.1.5 for source range channel inputs within 4 hours after entry into MODE 3 from MODE 2 is a more restrictive requirement.

TECHNICAL CHANGES - LESS RESTRICTIVE (SPECIFIC)

L1 The CTS is revised to adopt the "ALLOWABLE VALUE" column from ISTS Table 3.3.1-1 and Table 3.3.2-1. This column is added to provide an allowance for calibration tolerances, instrumentation uncertainties, instrument drift, and severe environment errors for those RPS and ESFAS channels that must function in harsh environments. The Allowable Values specified in Table 3.3.1-1 and Table 3.3.2-1 are conservatively set with respect to the analytical limits. In establishing these allowable values, some have been determined to be less conservative than the CTS trip setpoint limits. The less conservative parameters, which include OTΔT and OPΔT are considered to be a relaxation of requirements, which is less restrictive.

This change is acceptable, however, because the actual nominal trip setpoint is more conservative than that specified by the Allowable Value to account for changes in random measurement errors, such as drift during a surveillance interval. Setpoints in accordance with the Allowable Value ensure that safety limits are not violated during abnormal operational occurrences (AOOs), and 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 AOO or DBA and the equipment functions as designed. The Allowable Values listed in Table 3.3.1-1 and Table 3.3.2-1 are conservatively set with respect to the analytical limits, and are based on the methodology described in the company setpoint methodology procedure. The magnitudes of uncertainties are factored into the determination of each trip setpoint. All field sensors and signal processing equipment for these channels are assumed to operate within the allowances of these uncertainty magnitudes.

In addition, for the OTΔT and OPΔT Functions, the term "setting" is modified to "Nominal Trip Setpoint" and a Note is added to clarify channel OPERABILITY relative to actual trip settings. These changes are being made for consistency with the CP&L setpoint methodology. The setpoint calculations performed for each of the affected setpoints using the CP&L setpoint methodology demonstrate that a channel is OPERABLE if its actual trip setting, between CHANNEL CALIBRATIONS, exceeds the associated Nominal Trip Setpoint but is within the Allowable Value provided the channel is re-adjusted to within the established "as left" calibration tolerance band. The setpoint calculations also demonstrate that if a channel trip setting is within the established "as found" calibration tolerance band associated with the Trip Setpoint, no adjustment of the channel's calibration is necessary to ensure the channel is maintained OPERABLE for the length of the CHANNEL CALIBRATION interval. Note (3) is added to permit adjustment of the Nominal Trip Setpoints as required by Required Actions. Therefore, the Trip Setpoints are actually "nominal" values rather than "absolute" values.

L2 CTS Specifications 2.3.1.2.d and 2.3.1.2.e set the values of certain OTΔT and OPΔT parameters as being "=" to specific values. the specific values in CTS are normal values with an instrument tolerance of ± 10%. ITS Table 3.3.1-1, Note 1 modifies the OTΔT values to $\tau_1 \geq 20.08$ seconds and $\tau_2 \leq 3.08$ seconds and includes the 10% instrument tolerance. ITS Table 3.3.1-1 Note 2 modifies the OPΔT values to $\tau_3 \geq 9$ seconds and includes the 10% instrument tolerance. This is a relaxation of requirements, and is less restrictive. This change is acceptable, however, because these parameter settings are cycle specific and only permit installation of a more restrictive setpoint in the actual hardware. In addition, the instrument tolerance was evaluated against the analysis associated with RPS instrument time constants and found to be acceptable. Although these parameters normally do not change, they are subject to modification as a result of a reload safety analysis. This change is consistent with NUREG-1431.

than 48 hours, but the diesel is otherwise fully OPERABLE, a shutdown is required.

L30 Not Used.

L31 CTS Specification 3.8.1.b requires that the radiation monitors which initiate containment ventilation isolation be tested and verified to be OPERABLE immediately prior to refueling operations. This requirement is not retained in the ITS. This constitutes a relaxation of requirements, and is therefore less restrictive. This change is acceptable, however, because the radiation monitors are demonstrated OPERABLE at a Frequency of 92 days by performance of a CHANNEL OPERATIONAL TEST. The Frequency of 92 days is based on industry operating experience, considering instrument reliability and operating history data. A review of the surveillance test history was performed to validate that the impact, if any, on system availability is minimal as a result of the change in the surveillance test interval. This review of the surveillance test history, demonstrates that there are no failures that would invalidate the conclusion that the impact, if any, on system availability is minimal from a change to a 92 day surveillance interval. This change is consistent with NUREG-1431.

L32 CTS Table 3.4-1, Function 1, requires under certain channel inoperability conditions, that the unit be maintained in hot shutdown. ITS Specification 3.3.8, Required Action C, requires under similar conditions, that the inoperable channel be placed in trip in 6 hours, or be in MODE 3 in 12 hours, and MODE 4 in 18 hours. This is a relaxation of requirements, and is less restrictive. This change is acceptable, however, because placing the inoperable channel in trip maintains the AFW pump autostart Function OPERABLE, but in a one-out-of-two configuration, instead of two-out-of-three. The allowance of 6 hours to return the channel to OPERABLE status or place it in trip is consistent with WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990. This change is consistent with NUREG-1431.

As required by the NRC Safety Evaluation (dated April 30, 1990) accepting the generic reliability analysis in WCAP-10271-P-A, Supplement 2, Rev.1, CP&L has confirmed that the HBRSEP Unit No. 2 logic design of the affected instrumentation is bounded by that analyzed in the reliability analysis and the conclusions are applicable to the HBRSEP Unit No. 2 design. In addition, CP&L has confirmed that the instrument drift due to extended Surveillance Frequencies, associated with application of the generic reliability analysis to the HBRSEP Unit No. 2 instrumentation, is already properly accounted for in the setpoint calculation methodology.

L33 Not Used.

L34 Not used.

L35 CTS Table Note (*) for Table 3.5.2 is revised to "With Rod Control System capable of rod withdrawal, or one or more rods not fully inserted," and is incorporated into ITS Table 3.3.1-1, Note (a). This change reduces of Applicability in MODEs 3, 4, and 5 for Functions 1, 4, 18, 19, and 20 of ITS Table 3.3.1-1. This change relaxes requirements and is less restrictive. This change is acceptable because the remaining Applicability for Functions 1, 4, 18, 19, and 20 ensures that the reactor trip functions will be available when required. With the the rod control system capable of rod withdrawal or one or more rods not fully inserted, ITS Table 3.3.1-1 requires that the reactor trip system be OPERABLE for the source range and manual trip functions in MODES 3, 4, and 5. In this condition a shutdown bank may be fully withdrawn and the remaining control rods maintained at 5 steps off the bottom. Under these conditions, control rods may be credited in the Shutdown Margin (SDM). UFSAR Section 15.4.1, "Uncontrolled Rod Cluster Control Assembly Bank Withdrawal From Subcritical or Low Power," analyzes uncontrolled rod withdrawal from MODE 2 conditions. Since MODES 3, 4, and 5 include the requirement for reactivity < .99 k_{eff}, these MODES are bounded by the analysis in UFSAR Section 15.4.1. With the rod control system capable of rod withdrawal or one or more rods not fully inserted, ITS Table 3.3.1-1 requires the reactor trip system to be OPERABLE for source range and manual trip functions. In this condition, a malfunction of the rod control system could result in the uncontrolled rod withdrawal event as analyzed in UFSAR Section 15.4.1.

L36 CTS Table 3.5-2 ACTION 3 requires for an inoperable intermediate range neutron flux channel with THERMAL POWER above the P-6 setpoint, but below 10% RTP, that the inoperable channel be restored to OPERABLE status prior to increasing THERMAL POWER above 10% RTP. ITS Specification 3.3.1 ACTION F requires for an inoperable intermediate range neutron flux channel with THERMAL POWER above the P-6 setpoint, but below the P-10 setpoint, that THERMAL POWER either be reduced to below P-6 or increased above P-10 in 2 hours. The intermediate range neutron flux channels must be OPERABLE when the power level is above the

the emergency bus trip Function, because the three Degraded Voltage channels per bus are configured in a two-out-of-three logic, such that if any two channels see a degraded voltage condition, they will trip the bus. With one channel placed in trip, the two OPERABLE channels are still available to trip the bus in a one-out-of-two logic arrangement. The proposed change to the ACTIONS will not allow continuous operation such that a single failure will preclude DG initiation from mitigating the consequences of a design basis transient. Therefore, this change does not involve an increase in the probability or consequences of an accident previously evaluated.

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

   The proposed change does not involve any physical alteration of plant systems, structures or components, changes in parameters governing normal plant operation, or methods of operation. This change does not introduce any new modes of operation. Therefore, the possibility of a new or different kind of accident from any accident previously evaluated is not created.

3. Does this change involve a significant reduction in a margin of safety?

   The proposed change does not involve any physical alteration of plant systems, structures or components, changes in parameters governing normal plant operation, or methods of operation. This change does not introduce any new modes of operation. This change is consistent with WCAP-10271-P-A for this Function. No significant reduction in a margin of safety is involved with the change associated with declaring the associated diesel generator inoperable when a Required Action and associated Completion Time has not been met, since the Required Actions have been developed to assure the DG instrumentation remains capable of mitigating the consequences of design basis accidents or the supported components (DGs) declared inoperable and associated actions taken. This change also provides a benefit through the potential avoidance of an unnecessary plant transient when alternate compensatory measures are available to ensure the LOP instrumentation's intended function is satisfied. Therefore, this change does not involve a reduction in a margin of safety.

LESS RESTRICTIVE-SPECIFIC CHANGES
("L30" Labeled Comments/Discussions)

Not Used.

LESS RESTRICTIVE-SPECIFIC CHANGES
("L31" Labeled Comments/Discussions)

Carolina Power & Light Company has evaluated the proposed Technical Specification change and has concluded that it does not involve a significant hazards consideration. Our conclusion is in accordance with the criteria set forth in 10 CFR 50.92. The bases for the conclusion that the proposed change does not involve a significant hazards consideration are discussed below.

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

   The proposed change does not involve any physical alteration of plant systems, structures or components, changes in parameters governing normal plant operation, or methods of operation. This change eliminates an OPERABILITY test of the radiation monitors which actuate containment

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CTS

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE		FREQUENCY
[T4.1-1(30,47)]	SR 3.3.1.4 [A35]	----------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
[T4.1-1 (27)]	SR 3.3.1.5	Perform ACTUATION LOGIC TEST.	31 days on a STAGGERED TEST BASIS
[T4.1-1 (1)]	SR 3.3.1.6 [L40]	----------NOTE---------- Not required to be performed until 24 hours after THERMAL POWER is ≥ 50% RTP. ---------- Calibrate excore channels to agree with incore detector measurements.	92 EFPD
[T4.1-1 (1, 3-7,10,39,40)]	SR 3.3.1.7 [L40]	----------NOTE---------- Not required to be performed for source range instrumentation prior to entering MODE 3 from MODE 2 until 4 hours after entry into MODE 3. ---------- Perform COT.	92 days

(continued)

INSERT 3.3-11A

6

Supplement 8

Insert 3.3-11a

----------NOTE----------
Not required to be performed for the logic inputs from Source Range Neutron Flux detector channels prior to entering Mode 3 from Mode 2 until 4 hours after entry into MODE 3.

CTS

Table 3.3.1-1 (page 1 of 8)
Reactor Trip System Instrumentation
Protection

	FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	NOMINAL TRIP SETPOINT
[T 3.5-2(1)] [T4.1-1(46,47)]	1. Manual Reactor Trip	1,2	2	B	SR 3.3.1.14	NA	NA
		3, 4, 5 (a)	2	C	SR 3.3.1.14	NA	NA
[T 3.5-2(2)]	2. Power Range Neutron Flux						
[2.3.1.2.a] [T4.1-1 (1)]	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 ~~SR 3.3.1.16~~	≤ ~~109.2~~ 110.93 % RTP	~~109.6~~ 108 % RTP (2)
[2.3.1.1.a] [T4.1-1(1)]	b. Low	1 (b), 2	4	E	SR 3.3.1.1 SR 3.3.1.8 SR 3.3.1.11 ~~SR 3.3.1.16~~	≤ ~~25.8~~ 26.93 % RTP	~~25~~ 24 % RTP
	3. Power Range Neutron Flux Rate						
	a. High Positive Rate	1,2	4	E	SR 3.3.1.7 SR 3.3.1.11	≤ [6.8]% RTP with time constant ≥ [2] sec	≤ [5]% RTP with time constant ≥ [2] sec
	b. High Negative Rate	1,2	4	E	SR 3.3.1.7 SR 3.3.1.11 SR 3.3.1.16	≤ [6.8]% RTP with time constant ≥ [2] sec	≤ [5]% RTP with time constant ≥ [2] sec
[T3.5-2(3)] [T4.1-1(2)]	4. Intermediate Range Neutron Flux	1 (b), 2 (c)	2	F,G	SR 3.3.1.1 SR 3.3.1.8 SR 3.3.1.11	≤ ~~[31]~~ 37.02 % RTP	~~[25]~~ % RTP
		2 (d)	2	H	SR 3.3.1.1 SR 3.3.1.8 SR 3.3.1.11	≤ ~~[31]~~ % RTP	~~[25]~~ % RTP

(continued)

(a) Reviewer's Note: Unit specific implementations may contain only Allowable Value depending on Setpoint Study methodology used by the unit.

(b) With Reactor Trip Breakers (RTBs) closed and Rod Control System capable of rod withdrawal.

(c) Below the P-10 (Power Range Neutron Flux) interlocks.

(d) Above the P-6 (Intermediate Range Neutron Flux) interlocks.

(e) Below the P-6 (Intermediate Range Neutron Flux) interlocks.

INSERT 3.3.1-2

SUPPLEMENT 8

CTS

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	TRIP SETPOINT (NOMINAL)
[T3.5-2(4)] [T4.1-1(3)] [M12]	4. Source Range Neutron Flux	2 (d)	2	I,J	SR 3.3.1.1 SR 3.3.1.8 SR 3.3.1.11 SR 3.3.1.16	≤ 1.3E5 cps (1.28 E5)	≤ 1.0 E5 cps
		3 (a), 4 (a), 5 (a)	2	J,K	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.11 SR 3.3.1.16	≤ 1.3E5 cps	≤ 1.0 E5 cps
		3 (e), 4 (e), 5 (e)	1	L	SR 3.3.1.1 SR 3.3.1.11	N/A	N/A
[2.3.1.2.d] [T3.5-2(5)] [T4.1-1(4)]	5. Overtemperature ΔT	1,2	3	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 SR 3.3.1.16	Refer to Note 1 (Page 3.3-21)	Refer to Note 1 (Page 3.3-21)
[2.3.1.2.e] [T3.5-2(6)] [T4.1-1(4)]	6. Overpower ΔT	1,2	3	E	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.12 SR 3.3.1.16	Refer to Note 2 (Page 3.3-21)	Refer to Note 2 (Page 3.3-21)

SR 3.3.1.3
SR 3.3.1.6

(continued)

(a) Reviewer's Note: Unit specific implementations may contain only Allowable Value depending on Setpoint Study methodology used by the unit.

(b) With RTBs closed and Rod Control System capable of rod withdrawal.

(e) Below the P-6 (Intermediate Range Neutron Flux) interlocks.

(f) With the RTBs open. In this condition, source range Function does not provide reactor trip but does provide [input to the Boron Dilution Protection System (LCO 3.3.9), and] indication.

INSERT 3.3.1-2

Table 3.3.1-1 (page 3 of 8)
Reactor ~~Trip~~ Protection System Instrumentation

CTS

	FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	NOMINAL ~~TRIP~~ SETPOINT (a)
[2.3.1.2.c] [T3.5-2(7)] [T4.1-1(7)]	7 8 Pressurizer Pressure						
	a. Low	1 (f)	3	M	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10 ~~SR 3.3.1.16~~	≥ ~~1880~~ 1832.02 psig	~~1900~~ 1844 psig
[2.3.1.2.b] [T3.5-2(8)] [T4.1-1(7)]	b. High	1,2	3	E	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10 ~~SR 3.3.1.16~~	≤ ~~2385~~ 2381.11 psig	~~2385~~ 2376 psig
[2.3.1.3.a] [T3.5-2(9)] [T4.1-1(6)]	8 9 Pressurizer Water Level – High	1 (f)	3	M	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10	≤ ~~92.8~~ 91.64 %	~~92~~ 91 %
[2.3.1.2.f] [T3.5-2(10)] [T4.1-1(5)]	9 10 Reactor Coolant Flow – Low						
	a. Single Loop	1 (g)	3 per loop	M	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10 ~~SR 3.3.1.16~~	≥ ~~93.2~~ 93.47 %	~~90~~ 94.26 %
	b. Two Loops	1 (h)	3 per loop	M	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10 ~~SR 3.3.1.16~~	≥ ~~93.2~~ %	~~90~~ %

(continued)

(a) Reviewer's Note: Unit specific implementations may contain only Allowable Value depending on Setpoint Study methodology used by the unit.

(g) Above the P-7 (Low Power Reactor Trips Block) interlock.

(h) Above the P-8 (Power Range Neutron Flux) interlock.

(i) Above the P-7 (Low Power Reactor Trips Block) interlock and below the P-8 (Power Range Neutron Flux) interlock.

INSERT 3.3.1-2

CTS

Table 3.3.1-1 (page 4 of 8)
Reactor ~~Trip~~ Protection System Instrumentation

	FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	NOMINAL TRIP SETPOINT (a)
[M13]	10 ~~9~~. Reactor Coolant Pump (RCP) Breaker Position						
	a. Single Loop	1 ~~(g)~~ 9	1 per RCP	O	SR 3.3.1.14	NA	NA
	b. Two Loops	1 ~~(h)~~ h	1 per RCP	M	SR 3.3.1.14	NA	NA
[2.3.1.2.h] [T3.5-2(14)] [T4.1-1(8)]	11 ~~12~~. Undervoltage RCPs	1 ~~(f)~~ f	1 ~~(i)~~ per bus	M	SR 3.3.1.9 SR 3.3.1.10 ~~SR 3.3.1.16~~	≥ 2959 ~~4160~~ V	~~(f)~~ 3120 ~~4830~~ V
[2.3.1.2.g] [T3.5-2(13)] [T4.1-1(29)]	12 ~~13~~. Underfrequency RCPs	1 ~~(f)~~ f	1 ~~(i)~~ per bus	M	SR 3.3.1.9 ~~(f)~~ 10 SR 3.3.1.8 ~~SR 3.3.1.15~~	≥ 57.84 ~~58.3~~ Hz	~~(f)~~ 58.2 ~~57.5~~ Hz
[2.3.1.3.b] [T3.5-2(12)] [T4.1-1(11)]	13 ~~14~~. Steam Generator (SG) Water Level – Low Low	1,2	3 ~~(a)~~ per SG ~~(b)~~	E	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10 ~~SR 3.3.1.16~~	≥ 15.36 ~~18.3~~ %	~~(f)~~ 16 ~~17.3~~ %
[T3.5-2(16)] [T4.1-1(39,40)] [M14]	14 ~~15~~. SG Water Level – Low	1,2	2 per SG	E	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10 ~~SR 3.3.1.16~~	≥ 29.36 ~~28.3~~ %	~~(f)~~ 30 ~~28.3~~ %
	Coincident with Steam Flow/ Feedwater Flow Mismatch	1,2	2 per SG	E	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10 ~~SR 3.3.1.16~~	≤ 7.06E5 lbm/hr ~~42.9%~~ full steam flow at RTP	~~(f)~~ 6.4E5 lbm/hr ~~40%~~ full steam flow at RTP

(continued)

(a) Reviewer's Note: Unit specific implementations may contain only Allowable Value depending on Setpoint Study methodology used by the unit.

(g) Above the P-7 (Low Power Reactor Trips Block) interlock.

(h) Above the P-8 (Power Range Neutron Flux) interlock.

(i) Above the P-7 (Low Power Reactor Trips Block) interlock and below the P-8 (Power Range Neutron Flux) interlock.

INSERT 3.3.1-2

CTS

Table 3.3.1-1 (page 5 of 8)
Reactor Trip System Instrumentation

	FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	TRIP SETPOINT
[T3.5-2(11)] [T4.1-1(22)] [M13]	15. Turbine Trip						
	a. Low Oil Pressure	1	3	P	SR 3.3.1.10 SR 3.3.1.15	≥ 50 psig	45 psig
	b. Turbine Stop Valve Closure	1	4	P	SR 3.3.1.10 SR 3.3.1.15	≥ 1% open	≥ 1% open
[M13]	16. Safety Injection (SI) Input from Engineered Safety Feature Actuation System (ESFAS)	1,2	2 trains	Q	SR 3.3.1.14	NA	NA
[M13]	17. Reactor Trip System Interlocks						
	a. Intermediate Range Neutron Flux, P-6	2	2	S	SR 3.3.1.11 SR 3.3.1.13	≥ 6E-11 amp	1E-10 amp
	b. Low Power Reactor Trips Block, P-7	1	1 per train	T	SR 3.3.1.11 SR 3.3.1.13	NA	NA
	c. Power Range Neutron Flux, P-8	1	4	T	SR 3.3.1.11 SR 3.3.1.13	≤ 42.94% RTP	40% RTP
	d. Power Range Neutron Flux, P-9	1	4	T	SR 3.3.1.11 SR 3.3.1.13	≤ (52.2)% RTP	≤ (50)% RTP
	e. Power Range Neutron Flux, P-10	1,2	4	S	SR 3.3.1.11 SR 3.3.1.13	≥ 7.06% RTP and ≤ 12.94% RTP	10% RTP
[T4.1-1(25)]	f. Turbine Impulse Pressure, P-7 input	1	2	T	SR 3.3.1.10 SR 3.3.1.10 SR 3.3.1.13	≤ 10.71% turbine power	10% turbine power

(continued)

(a) Reviewer's Note: Unit specific implementations may contain only Allowable Value depending on Setpoint Study methodology used by the unit.

(e) Below the P-6 (Intermediate Range Neutron Flux) interlocks.

(j) Above the P-9 (Power Range Neutron Flux) interlock.

INSERT 3.3.1-2

CTS [T3.5-2]

ITS Insert 3.3.1-2 (RPS Instrumentation)

[*] (a) Reviewer's Note: Unit specific implementations may contain only Allowable Value depending on Setpoint Study methodology used by the unit. (16)

[**] (b) With Reactor Trip Breakers (RTBs) closed and Rod Control System capable of rod withdrawal, or one or more rods not fully inserted (17)

[A30] (c) Below the P-10 (Power Range Neutron Flux) interlocks.

[***] (d) Above the P-6 (Intermediate Range Neutron Flux) interlocks.

[A31], (e) Below the P-6 (Intermediate Range Neutron Flux) interlocks.

[*****] [2.3.2.1] (f) With the RTBs open. In this condition, source range Function does not provide reactor trip but does provide [input to the Boron Dilution Protection System (LCO 3.3.9), and] indication and alarm (18)

[M50] (g) Above the P-7 (Low Power Reactor Trips Block) interlock.

[2.3.2.1] [****] (h) Above the P-8 (Power Range Neutron Flux) interlock.

(i) Above the P-7 (Low Power Reactor Trips Block) interlock and below the P-8 (Power Range Neutron Flux) interlock.

(j) Above the P-9 (Power Range Neutron Flux) interlock. (13)

[A32] (k) Including any reactor trip bypass breakers that are racked in and closed for bypassing an RTB. (68)

[M1] [L1] (1) A channel is OPERABLE with an actual Trip Setpoint value found outside its calibration tolerance band provided the Trip Setpoint value is conservative with respect to its associated Allowable Value and the channel is re-adjusted to within the established calibration tolerance band of the Nominal Trip Setpoint.

[A41] (j) Below the P-6 (Intermediate Range Neutron Flux) interlock for the logic inputs from Source Range Neutron Flux detector channels (67)

(68)

(2) The Nominal Trip Setpoint is as stated unless reduced as required by one or more of the following requirements: LCO 3.2.1 Required Action A.2.2; LCO 3.2.2 Required Action A.2.2; or LCO 3.2.1 Required Action B.2.

(3) The Nominal Trip Setpoint is as stated unless reduced as required by LCO 3.2.1 Required Action A.2.3.

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Table 3.3.1-1 (page 6 of 8)
Reactor ~~Trip~~ Protection System Instrumentation

	FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	NOMINAL TRIP SETPOINT (1)
[3.10.5.1.a] [T4.1-1(30,47)]	18. Reactor Trip Breakers	1,2	2 trains	B	SR 3.3.1.4	NA	NA
		3, 4, 5	2 trains	C	SR 3.3.1.4	NA	NA
[3.10.5.1.a] [T4.1-1(30,47)]	19. Reactor Trip Breaker Undervoltage and Shunt Trip Mechanisms	1,2	1 each per RTB	U	SR 3.3.1.4	NA	NA
		3, 4, 5	1 each per RTB	C	SR 3.3.1.4	NA	NA
[3.10.5.1.c] [T4.1-1(27)]	20. Automatic Trip Logic	1,2	2 trains	Q	SR 3.3.1.5	NA	NA
		3, 4, 5	2 trains	C	SR 3.3.1.5	NA	NA

(a) Reviewer's Note: Unit specific implementations may contain only Allowable Value depending on Setpoint Study methodology used by the unit.

(b) With RTBs closed and Rod Control System capable of rod withdrawal.

(k) Including any reactor trip bypass breakers that are racked in and closed for bypassing an RTB.

INSERT 3.3.1-2

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Table 3.3.1-1 (page 7 of 8)
Reactor ~~Trip~~ Protection System Instrumentation

CTS

[2.3.1.2.d] Note 1: Overtemperature ΔT

The Overtemperature ΔT Function Allowable Value shall not exceed the following ~~Trip~~ Nominal Setpoint by more than ~~[3.8]~~ 2.96 % of ΔT span. 68

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

Where: ΔT is measured RCS ΔT, °F.
ΔT_0 is the indicated ΔT at RTP, °F.
s is the Laplace transform operator, sec^{-1}.
T is the measured RCS average temperature, °F.
T' is the ~~nominal~~ T_{avg} at RTP, ≤ ~~[588]~~ 575.4 °F.
P is the measured pressurizer pressure, psig
P' is the ~~nominal~~ reference RCS operating pressure, ≤ ~~[2235]~~ psig

K_1 ≤ ~~[1.0949]~~ 1.1265 K_2 ≥ ~~[0.01388]~~ 0.01228 /°F K_3 = ~~[0.00867]~~ 0.00089 /psig
τ_1 ≥ ~~[8]~~ 20.08 sec τ_2 ≤ ~~[3]~~ sec τ_3 ≤ ~~[2]~~ sec
~~τ_4 ≥ [33] sec~~ ~~τ_5 ≤ [4] sec~~ ~~τ_6 ≥ [2] sec~~ 3.08

$f_1(\Delta I)$ =
- $1.26\{35 + (q_t - q_b)\}$ when $q_t - q_b$ ≤ ~~-[35]~~ % RTP
- 0% of RTP when ~~-[35]% RTP < $q_t - q_b$ ≤ [7]% RTP~~
- $-1.05\{(q_t - q_b) - 7\}$ when ~~$q_t - q_b$ > [7]% RTP~~

Where q_t and q_b are percent RTP in the upper and lower halves of the core, respectively, and $q_t + q_b$ is the total THERMAL POWER in percent RTP.

- $2.4\{(q_b - q_T) - 17\}$ when $q_T - q_b$ < -17% RTP
- 0% of RTP when -17% RTP ≤ $q_T - q_b$ ≤ 12% RTP
- $2.4\{(q_T - q_b) - 12\}$ when $q_T - q_b$ > 12% RTP

$$\Delta T_{setpoint} \le \Delta T_0 \left\{K_1 - K_2 \frac{(1+\tau_1 s)}{(1+\tau_2 s)}(T - T') + K_3 (P - P') - f(\Delta I)\right\}$$

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1

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Table 3.3.1-1 (page 8 of 8)
Reactor ~~Trip~~ Protection System Instrumentation

CTS

[2.3.1.2.e]

Note 2: Overpower ΔT

The Overpower ΔT Function Allowable Value shall not exceed the following Nominal Trip Setpoint by more than ~~[5]~~ 3.17 % of ΔT span.

68

$$\Delta T \frac{(1+\tau_1 s)}{(1+\tau_2 s)}\left[\frac{1}{1+\tau_3 s}\right] \le \Delta T_0 \left\{K_4 - K_5 \frac{\tau_3 s}{1+\tau_3 s}\left[\frac{1}{1+\tau_6 s}\right] T - K_6\left[T \frac{1}{1+\tau_6 s} - T''\right] - f_2(\Delta I)\right\}$$

Where: ~~ΔT is measured RCS ΔT, °F.~~
ΔT_0 is the indicated ΔT at RTP, °F.
s is the Laplace transform operator, sec^{-1}.
T is the measured RCS average temperature, °F.
T' is the ~~nominal~~ reference T_{avg} at RTP, ≤ ~~[588]~~ 575.4 °F.

K_4 ≤ ~~[1.09]~~ ≤ 1.06

K_5 ≥ ~~[0.02]~~ 0.02/°F for increasing T_{avg}
~~[0]~~ 0/°F for decreasing T_{avg}

K_6 ≥ ~~[0.00128]~~ 0.00277/°F when T > T'
~~[0]~~ 0/°F when T ≤ T'

τ_1 ≥ ~~[8]~~ sec τ_2 ≤ ~~[3]~~ sec
τ_6 ≤ ~~[2]~~ sec τ_7 ≥ ~~[10]~~ sec

τ_3 ~~≤ [2]~~ ≥9 sec

$f_2(\Delta I)$ = ~~0% RTP for all ΔI~~ as defined in Note 1 for Overtemperature ΔT

$$\Delta T_{setpoint} \le \Delta T_0 \left\{K_4 - K_5\left(\frac{\tau_3 s}{1+\tau_3 s}\right) T - K_6 (T - T') - f(\Delta I)\right\}$$

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Table 3.3.2-1 (page 1 of 8)
Engineered Safety Feature Actuation System Instrumentation

CTS

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	NOMINAL TRIP SETPOINT
1. Safety Injection						
[T3.5-3(1.A)] a. Manual Initiation	1,2,3,4	2	B	SR 3.3.2.8	NA	NA
[T4.1-1(27)] [4.5.1.1] [M27] [L13] b. Automatic Actuation Logic and Actuation Relays	1,2,3,4	2 trains	C	SR 3.3.2.2 SR 3.3.2.5 SR 3.3.2.6	NA	NA
[T3.5-1(1)] [T3.5-3(1.B)] c. Containment Pressure – High	1,2,3	3	E	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.6 ~~SR 3.3.2.10~~	≤ 3.86 psig	3.60 psig
[T3.5-1(3)] [T3.5-3(1.D)] d. Pressurizer Pressure – Low	1,2,3	3	D	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.6 ~~SR 3.3.2.10~~	≥ 1839 psig	≥ 1850 psig
e. Steam Line Pressure						
(1) Low	1,2,3[(b)]	3 per steam line	D	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10	≥ [635] psig (c)	≥ [675] psig (c)
[T3.5-1(4)] [T3.5-3(1.C)] (2) High Differential Pressure Between Steam Lines	1,2,3	3 per steam line	D	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.6 ~~SR 3.3.2.10~~	≤ 106 psig	≤ 100 psig
[T3.5-4(2.A)] f. High Steam Flow in Two Steam Lines	1,2,3	2 per steam line	D	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.6 ~~SR 3.3.2.10~~	(c)	(d)
Coincident with T_{avg} – Low	1,2,3	1 per loop	D	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.6 ~~SR 3.3.2.10~~	≥ 550.6 °F	≥ 553 °F

(continued)

(a) Reviewer's Note: Unit specific implementations may contain only Allowable Value depending on Setpoint Study methodology used by the unit.
(b) Above the P-11 (Pressurizer Pressure) interlock.
(c) Time constants used in the lead/lag controller are $t_1 \geq [50]$ seconds and $t_2 \leq [5]$ seconds.
(d) Above the P-12 (T_{avg} – Low Low) interlock.
(e) Less than or equal to a function defined as ΔP corresponding to [44]% full steam flow below [20]% load, and ΔP increasing linearly from [44]% full steam flow at [20]% load to [114]% full steam flow at [100]% load, and ΔP corresponding to [114]% full steam flow above 100% load.
(f) Less than or equal to a function defined as ΔP corresponding to [40]% full steam flow between [0]% and [20]% load and then a ΔP increasing linearly from [40]% steam flow at [20]% load to [110]% full steam flow at [100]% load.

INSERT 3.3.2-4

Table 3.3.2-1 (page 2 of 8)
Engineered Safety Feature Actuation System Instrumentation

CTS

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	NOMINAL TRIP SETPOINT
1. Safety Injection (continued)						
[T3.5-4(2.B)] g. High Steam Flow in Two Steam Lines	1,2,3	2 per steam line	D	SR 3.3.2.1 SR 3.3.2.6 SR 3.3.2.8 ~~SR 3.3.2.10~~		
Coincident with Steam Line Pressure – Low	1,2,3	1 per steam line	D	SR 3.3.2.1 SR 3.3.2.6 SR 3.3.2.8 ~~SR 3.3.2.10~~	≥ [605.05] psig	[614] psig
2. Containment Spray						
[T3.5-3(2.A)] a. Manual Initiation	1,2,3,4	2 per train, 2 trains	B	SR 3.3.2.6	NA	NA
[T4.1-1(27)] [4.5.1.3] [M27] [L13] b. Automatic Actuation Logic and Actuation Relays	1,2,3,4	2 trains	C	SR 3.3.2.2 SR 3.3.2.6 SR 3.3.2.5	NA	NA
c. Containment Pressure						
[T3.5-1(2)] [T3.5-3(2.B)] High-3 (High High)	1,2,3,4	6 (2 sets of 3)	E	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.8 ~~SR 3.3.2.10~~	≤ [12.35] psig	[12.05] psig
~~High-3 (Two Loop Plants)~~	~~1,2,3~~	~~[3] sets of [2]~~	~~E~~	~~SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10~~	~~≤ [12.31] psig~~	~~≤ [12.05] psig~~

(continued)

(a) Reviewer's Note: Unit specific implementations may contain only Allowable Value depending on Setpoint Study methodology used by the unit.
(c) Time constants used in the lead/lag controller are $t_1 \geq$ [50] seconds and $t_2 \leq$ [5] seconds.
(d) Above the P-12 (T_{avg} – Low Low) interlock.
(e) Less than or equal to a function defined as ΔP corresponding to [44]% full steam flow below [20]% load, and ΔP increasing linearly from [44]% full steam flow at [20]% load to [114]% full steam flow at [100]% load, and ΔP corresponding to [114]% full steam flow above 100% load.
(f) Less than or equal to a function defined as ΔP corresponding to [40]% full steam flow between [0]% and [20]% load and then a ΔP increasing linearly from [40]% steam flow at [20]% load to [110]% full steam flow at [100]% load.

INSERT 3.3.2-4

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Table 3.3.2-1 (page 3 of 8)
Engineered Safety Feature Actuation System Instrumentation

CTS

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	~~TRIP~~ NOMINAL SETPOINT
3. Containment Isolation						
a. Phase A Isolation						
[T3.5-4(1.A.ii)] [T4.1-3(5)] (1) Manual Initiation	1,2,3,4	2	B	SR 3.3.2.~~8~~ 6	NA	NA
[T3.5-4(1.A.i)] [M27] [L13] (2) Automatic Actuation Logic and Actuation Relays	1,2,3,4	2 trains	C	SR 3.3.2.2 SR 3.3.2.~~6~~ 3 SR 3.3.2.~~8~~ 5	NA	NA
(3) Safety Injection	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.					
[T3.5-4(1.B)] b. Phase B Isolation						
(1) Manual Initiation	1,2,3,4	~~2 per train, 2 trains~~ I	~~B~~ I	SR 3.3.2.~~8~~ 6	NA	NA
[M27] [L13] (2) Automatic Actuation Logic and Actuation Relays	1,2,3,4	2 trains	C	SR 3.3.2.2 SR 3.3.2.~~6~~ 3 SR 3.3.2.~~8~~ 5	NA	NA
(3) Containment Pressure ~~(High-High)~~	1,2,3,4	~~(2)~~ 6 (2 sets of 3)	E	SR 3.3.2.1 4 SR 3.3.2.~~6~~ 7 SR 3.3.2.~~8~~ ~~SR 3.3.2.10~~	≤ ~~12.41~~ 20.45 psig	~~≤ 12.05~~ 20 psig
4. Steam Line Isolation						
[T3.5-4(2.D)] a. Manual Initiation	1,2,~~3~~ (e)	~~2~~ 1 per steam line	F	SR 3.3.2.~~8~~ 6	NA	NA
[T4.1-1(27)] [M27] [L13] b. Automatic Actuation Logic and Actuation Relays	1,2,~~3~~ (e)	2 trains	G	SR 3.3.2.2 SR 3.3.2.~~6~~ 3 SR 3.3.2.~~8~~ 5	NA	NA

(continued)

(a) Reviewer's Note: Unit specific implementations may contain only Allowable Value depending on Setpoint Study methodology used by the unit.
(i) Except when all MSIVs are closed and [de-activated].

INSERT 3.3.2-4

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Table 3.3.2-1 (page 4 of 8)
Engineered Safety Feature Actuation System Instrumentation

CTS

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	NOMINAL ~~TRIP~~ SETPOINT
4. Steam Line Isolation (continued)		6 (2 sets of 3)				
[T3.5-4(2.c)] c. Containment Pressure – High (High)	1,2, 3		D	SR 3.3.2.1 SR 3.3.2.6 SR 3.3.2.8 ~~SR 3.3.2.10~~	≤ ~~[6.45]~~ 20.45 psig	~~[6.35]~~ 20 psig
d. Steam Line Pressure						
(1) Low	1,2(i), 3(b)(i)	3 per steam line	D	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10	≥ [635](c) psig	≥ [675](c) psig
(2) Negative Rate – High	3(g)(i)	3 per steam line	D	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10	≤ [121.6](h) psi/sec	≤ [110](h) psi/sec
[T3.5-1(5)] [T3.5-3(1.e)] High Steam Flow in Two Steam Lines	1,2(e), 3(e)	2 per steam line	D	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.8 ~~SR 3.3.2.10~~	(c)	(d)
Coincident with T_{avg} – Low ~~Low~~	1,2(f), 3(f)(b)	1 per loop	D	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.8 ~~SR 3.3.2.10~~	≥ ~~[550.6]~~ 541.50 °F	~~[553]~~ 543 °F

(continued)

(a) Reviewer's Note: Unit specific implementations may contain only Allowable Value depending on Setpoint Study methodology used by the unit.
(b) Above the P-11 (Pressurizer Pressure) interlock.
(c) Time constants used in the lead/lag controller are t_1 ≥ [50] seconds and t_2 ≤ [5] seconds.
(d) Above the P-12 (T_{avg} – Low Low) interlock.
(e) Less than or equal to a function defined as ΔP corresponding to [44]% full steam flow below [20]% load, ΔP increasing linearly from [44]% full steam flow at [20]% load to [114]% full steam flow at [100]% load, and ΔP corresponding to [114]% full steam flow above 100% load.
(f) Less than or equal to a function defined as ΔP corresponding to [40]% full steam flow between [0]% and [20]% load and then a ΔP increasing linearly from [40]% steam flow at [20]% load to [110]% full steam flow at [100]% load.
(g) Below the P-11 (Pressurizer Pressure) interlock.
(h) Time constant utilized in the rate/lag controller is ≤ [50] seconds.
(i) Except when all MSIVs are closed and [de-activated].

INSERT 3.3.2-4

Table 3.3.2-1 (page 5 of 8)
Engineered Safety Feature Actuation System Instrumentation

CTS

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	NOMINAL ~~TRIP~~ SETPOINT
4. Steam Line Isolation (continued)						
[T3.5-1(5)] [T3.5-3(4)] High Steam Flow in Two Steam Lines	1,2, 3	2 per steam line	D	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 ~~SR 3.3.2.10~~		
Coincident with Steam Line Pressure – Low	1,2, 3	1 per steam line	D	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 ~~SR 3.3.2.10~~	≥ [605.05] psig	[614] psig
g. High Steam Flow	1,2(i), 3(i)	2 per steam line	D	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10	≤ [25]% of full steam flow at no load steam pressure	≤ [ ] full steam flow at no load steam pressure
Coincident with Safety Injection	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.					
and						
Coincident with T_{avg} – Low Low	1,2(i), 3(d)(i)	[2] per loop	D	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10	≥ [550.6]°F	≥ [553]°F
h. High High Steam Flow	1,2(i), 3(i)	2 per steam line	D	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10	≤ [130]% of full steam flow at full load steam pressure	≤ [ ] of full steam flow at full load steam pressure
Coincident with Safety Injection	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.					

(continued)

(a) Reviewer's Note: Unit specific implementations may contain only Allowable Value depending on Setpoint Study methodology used by the unit.
(d) Above the P-12 (T_{avg} – Low Low) interlock.
(i) Except when all MSIVs are closed and [de-activated].

INSERT 3.3.2-4

Supplement 8

Table 3.3.2-1 (page 6 of 8)
Engineered Safety Feature Actuation System Instrumentation

CTS

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	NOMINAL TRIP SETPOINT
5. ~~Turbine Trip and~~ Feedwater Isolation						
[T3.5-4(3.A)] [413] a. Automatic Actuation Logic and Actuation Relays	1,2, (3)	2 trains	G	SR 3.3.2.2 SR 3.3.2.4 SR 3.3.2.6	NA	NA
b. SG Water Level – High High (P-14)	1,2(j), [3](j)	[3] per SG	[D]	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10	≤ [84.2]%	≤ [82.4]%
[M27] Safety Injection	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.					
6. Auxiliary Feedwater						
a. Automatic Actuation Logic and Actuation Relays (Solid State Protection System)	1,2,3	2 trains	G	SR 3.3.2.2 SR 3.3.2.4 SR 3.3.2.6	NA	NA
b. Automatic Actuation Logic and Actuation Relays (Balance of Plant ESFAS)	1,2,3	2 trains	G	SR 3.3.2.3	NA	NA
c. SG Water Level – Low Low	1,2,3	[3] per SG	D	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10	≥ [30.4]%	≥ [32.2]%

(continued)

(a) Reviewer's Note: Unit specific implementations may contain only Allowable Value depending on Setpoint Study methodology used by the unit.
(j) Except when all MFIVs, MFRVs, [and associated bypass valves] are closed and [de-activated] [or isolated by a closed manual valve].

INSERT 3.3.2-4

Supplement 8

Table 3.3.2-1 (page 7 of 8)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	NOMINAL ~~TRIP~~ SETPOINT (a)
6. Auxiliary Feedwater (continued)						
d. Safety Injection	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.					
e. Loss of Offsite Power	1,2,3	[3] per bus	F	SR 3.3.2.7 SR 3.3.2.9 SR 3.3.2.10	≥ [2912] V with ≤ 0.8 sec time delay	≥ [2975] V with ≤ 0.8 sec time delay
f. Undervoltage Reactor Coolant Pump	1,2	[3] per bus	I	SR 3.3.2.7 SR 3.3.2.9 SR 3.3.2.10	≥ [69]% bus voltage	≥ [70]% bus voltage
g. Trip of all Main Feedwater Pumps	1,2	[2] per pump	J	SR 3.3.2.8 SR 3.3.2.9 SR 3.3.2.10	≥ [ ] psig	≥ [ ] psig
h. Auxiliary Feedwater Pump Suction Transfer on Suction Pressure – Low	1,2,3	[2]	F	SR 3.3.2.1 SR 3.3.2.7 SR 3.3.2.9	≥ [20.53] [psia]	≥ [ ] [psia]
7. Automatic Switchover to Containment Sump						
a. Automatic Actuation Logic and Actuation Relays	1,2,3,4	2 trains	C	SR 3.3.2.2 SR 3.3.2.4 SR 3.3.2.6	NA	NA
b. Refueling Water Storage Tank (RWST) Level – Low Low	1,2,3,4	4	K	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10	≥ [15]% and ≤ [ ]%	≥ [ ] and ≤ [ ]
Coincident with Safety Injection	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.					

(continued)

(a) Reviewer's Note: Unit specific implementations may contain only Allowable Value depending on Setpoint Study methodology used by the unit.

INSERT 3.3.2-4

Table 3.3.2-1 (page 8 of 8)
Engineered Safety Feature Actuation System Instrumentation

CTS

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	NOMINAL ~~TRIP~~ SETPOINT (a) (1)
7. Automatic Switchover to Containment Sump (continued)						
c. RWST Level – Low Low	1,2,3,4	4	K	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10	≥ [15]%	≥ [18]%
Coincident with Safety Injection	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.					
and						
Coincident with Containment Sump Level – High	1,2,3,4	4	K	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9 SR 3.3.2.10	≤ [30] in. above el. [703] ft	≤ [ ] in. above el. [ ] ft
[M27] 8. ESFAS Interlocks						
a. Reactor Trip, P-4	1,2,3	1 per train, 2 trains	F	SR 3.3.2.11	NA	NA
b. Pressurizer Pressure P-11 Low	1,2,3	3	H	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9	≤ 2005.11 (1996) psig	≥ 2000 psig
c. T_{avg} – Low Low, P-12	1,2,3	1 per loop	H	SR 3.3.2.1 SR 3.3.2.5 SR 3.3.2.9	≤ 544.50 (538.80) °F	≥ 543 (535) °F

(a) Reviewer's Note: Unit specific implementations may contain only Allowable Value depending on Setpoint Study methodology used by the unit.

INSERT 3.3.2-4

Supplement 8

ITS Insert 3.3.2-4 (ESFAS Instrumentation)

CTS

(a) Reviewer's Note: Unit specific implementations may contain only Allowable Value depending on Setpoint Study methodology used by the unit. 16

[T3.5-3(#)] (a) (b) Above the P-11 (Pressurizer Pressure) interlock.

(c) Time constants used in the Lead/Lag controller are $t_1 \geq$ [50] seconds and $t_2 \leq$ [5] seconds. 30

[T3.5-3(##)] (d) (b) Above the P-12 T_{avg} - Low Low interlock.

(c) (e) Less than or equal to a function defined as ΔP corresponding to [44]% full steam flow below [20]% load, and ΔP increasing linearly from [44]% full steam flow at [20]% load to [114]% full steam flow at [100]% load, and ΔP corresponding to [114]% full steam flow above 100% load. 41.58 110.5

(d) (f) Less than or equal to a function defined as ΔP corresponding to [40]% full steam flow between [0]% and [20]% load and then a ΔP increasing linearly from [40]% steam flow at [20]% load to [110]% full steam flow at [100]% load. 37.25 37.25 109

(g) Below the P-11 (Pressurizer Pressure) interlock.

(h) Time constant utilized in the rate/lag controller is $\leq$ [50] seconds. 30

(e) (i) Except when all MSIVs are closed and [deactivated].

(f) (j) Except when all MFIVs, MFRVs, and associated bypass valves are closed and [deactivated] or isolated by a closed manual valve.

68

[M1] (1) A channel is OPERABLE with an actual Trip Setpoint value found outside its calibration tolerance band provided the Trip Setpoint value is conservative with respect to its associated Allowable Value and the channel is re-adjusted to within the established Calibration tolerance band of the Nominal Trip Setpoint.

Supplement 8

3.3 INSTRUMENTATION

CTS

3.3.5 Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation

[T3.5-5 (3)] LCO 3.3.5 ~~Three~~ Two channels per bus of the loss of voltage Function and ~~three~~ channels per bus of the degraded voltage Function shall be OPERABLE.

[T3.5-5(3)] APPLICABILITY: MODES 1, 2, 3, and 4.
When associated DG is required to be OPERABLE by LCO 3.8.2, "AC Sources – Shutdown."

INSERT 3.3.5-1 (46)

ACTIONS

[A5]

NOTE
Separate Condition entry is allowed for each Function.

Supplement 4

CONDITION	REQUIRED ACTION	COMPLETION TIME
[T3.5-3 Action 14] (B) (A) ~~One or more~~ Functions with one channel per bus inoperable. Degraded Voltage	(A) 1 (B) NOTE ~~The inoperable channel may be bypassed for up to 4 hours for surveillance testing of other channels.~~ Place channel in trip.	6 hours
[M37] (B) (C) ~~One or more~~ Functions with two or more channels per bus inoperable.	(B) 1 (C) Restore all but one channel to OPERABLE status.	1 hour

INSERT 3.3.5-2 (47)

Supplement 8 (69) (47)

(continued)

CTS

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
[T 3.5-1(6)] [T4.1-1(32)] SR 3.3.5.8	Perform CHANNEL CALIBRATION with ~~[setpoint Allowable Value]~~ [Trip Setpoint ~~and Allowable Value~~] as follows:	~~[18]~~ months
	a. ~~Loss of voltage Allowable Value ≥ [2912] V with a time delay of [0.8] ± [ ] second.~~	328 V ± 10% Trip Setpoint of ≤ 1 second (at zero voltage).
	~~Loss of voltage Trip Setpoint ≥ [2975] V with a time delay of [0.8] ± [ ] second.~~	
	b. ~~Degraded voltage Allowable Value ≥ [3683] V with a time delay of [20] ± [ ] seconds.~~ 430 v ± 4 ; 10 ; 0.5	Trip Setpoint ± of
	~~Degraded voltage Trip Setpoint ≥ [3746] V with a time delay of [20] ± [ ] seconds.~~	

CTS

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One channel inoperable. [T3.4-1(1)] [M48]	C.1 Place channel in trip. OR C.2.1 Be in MODE 3. AND C.2.2 Be in MODE 4.	6 hours 12 hours 18 hours
D. One channel inoperable. [T 3.4-1 Note 2]	D.1 Restore channel to OPERABLE status. OR D.2.1 Be in MODE 3. AND D.2.2 Be in MODE 4.	48 hours 54 hours 60 hours
E. One Main Feedwater Pumps trip channel inoperable. [T3.4-1 Note 2]	E.1 Restore channel to OPERABLE status. OR E.2 Be in MODE 3.	48 hours 54 hours

ITS Insert 3.3.8-1 (AFW System Instrumentation)

CTS

Table 3.3.8-1 (page 1 of 1)
Auxiliary Feedwater System Instrumentation

	FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	NOMINAL TRIP SETPOINT (1)
[M48] [T3.4-1(1)] [T3.4-2(a)] [T4.8-1(c)]	1. SG Water Level–Low Low	1,2,3	3 per SG	~~B~~ C Supplement 7	SR 3.3.8.1 SR 3.3.8.2 SR 3.3.8.4	≥ 15.36 %	~~%~~ 16% (68)
[T3.4-1(3)] [T3.4-2(c)] [T4.8-1(e)]	2. Safety Injection	Refer to LCO 3.3.2, "ESFAS Instrumentation," Function 1, for all initiation functions and requirements.					
[T3.4-1(4)] [T3.4-2(d)] [T4.8-1(d)]	3. Loss of Offsite Power	1,2,3	2 per bus	~~E~~ D	SR 3.3.8.3 SR 3.3.8.4	NA ~~328 V ± 10% with ≤ 1 sec time delay~~	328 V ± 10% with ≤ 1sec time delay
[T3.4-1(2)] [T3.4-2(b)] [T4.8-1(b)]	4. Undervoltage Reactor Coolant Pump	1,2,3	2 per bus	B	SR 3.3.8.3 SR 3.3.8.4	≥ 2959 V	~~%~~ 3120 V (68)
[T3.4-1(5)] [T4.8-1(e)]	5. Trip of all Main Feedwater Pumps	1,2	1 per pump	~~B~~ E Supplement 7	SR 3.3.8.3	NA	NA

[M1] (1) A channel is OPERABLE with an actual Trip Setpoint value found outside its calibration tolerance band provided the Trip Setpoint value is conservative with respect to its associated Allowable Value and the channel is re-adjusted to within the established calibration tolerance band of the Nominal Trip Setpoint. (68)

Supplement 8

3.3.1.15 (TADOT). The Allowable Value and Trip Setpoint are revised to "NA," because it is not possible to calibrate the valve position due to stop valve and position indication design.

13 ITS Table 3.3.1-1, Item 18.d, Power Range Neutron Flux (P-9), is not adopted. The P-9 interlock is not used; rather the P-7 interlock is used to automatically activate and deactivate the high power trips. Footnote (j) is also deleted. Subsequent functions are renumbered accordingly.

14 ITS Table 3.3.1-1, Item 18.e, Turbine Impulse Pressure (P-13) terminology is changed to "Turbine Impulse Pressure, P-7 input." Turbine impulse pressure input to P-7 is not referred to as P-13.

15 ITS Table 3.3.1-1, Note 1 and Note 2, Overtemperature ΔT and Overpower ΔT, are modified to reflect the plant specific algorithm for determining the Overtemperature ΔT and Overpower ΔT setpoints from plant input parameters.

16 ITS Table 3.3.1-1 and Table 3.3.2-1: "Reviewer's Note," and references to the "Reviewer's Note," are not adopted. Subsequent notes are renumbered accordingly. In addition, since τ_3 is utilized in the plant specific algorithm different than τ_3 is utilized in the ISTS Table 3.3.1-1 algorithm, τ_3 is modified to "≥" which is consistent with the plant specific analysis associated with RPS time constants.

17 ITS Table 3.3.1-1, footnote (a), is modified to state, "With Rod Control System capable of rod withdrawal, or one or more rods not fully inserted." When the reactor trip breakers are closed and shutdown bank(s) are withdrawn, then these rods are credited as part of the shutdown margin and safety analyses as discussed in UFSAR Section 15.7.1. Because they are credited in the shutdown margin as being "trippable," it follows that those Functions necessary for manual or automatic tripping of the reactor be operable when the rods are not fully inserted, or are capable of being withdrawn. The continuous rod withdrawal accident is not the only reactivity transient of concern during MODES 3, 4, and 5. Steam line break and boron dilution accidents are also mitigated by the RPS when shutdown or control banks are withdrawn. The Note ensures that the RPS is operable in the condition that a shutdown bank is fully withdrawn (i.e., not capable of withdrawal) and the shutdown bank is credited for SDM.

18 ITS Table 3.3.1-1, footnote (e), is modified by acknowledging the high neutron flux at shutdown alarm function provided by the source range instrumentation. This reference is added because of the importance of this alarm when the reactor trip breakers are open.

19 ISTS 3.3.2, "Notes" in ACTIONS C, D, and G are not adopted. Due to the plant design, maintenance or surveillance testing of a single channel

can not be performed without causing all channels of the associated

34 Not used.

35 Not used.

36 Not used.

37 Not used.

38 ITS Table 3.3.2-1, Function 5, Feedwater Isolation, is modified to reflect that the plant design basis is such that ESFAS does not provide a direct Turbine Trip Function. The Turbine Trip is initiated through the RPS, upon ESFAS actuation.

39 Not used.

40 ITS Table 3.3.2-1, Function 5.b, Steam Generator Water Level-High High signal to Feedwater Isolation, is not adopted. This Function is not classified as an Engineered Safety Feature in the plant design basis and current licensing basis.

41 ITS Table 3.3.2-1, Function 6, Auxiliary Feedwater (AFW) is not adopted as an Engineered Safety Feature. The AFW System is not classified as an Engineered Safety Feature in the plant design basis and current licensing basis. AFW instrumentation and actuation requirements are addressed in a new ITS Specification 3.3.8.

42 The Allowable Value for ITS Table 3.3.2-1 Function 6.b, T_{avg}-Low, is modified from "≥" to "≤." This change is made to be consistent with HBRSEP, Unit No. 2 plant design. The T_{avg}-Low interlock function at HBRSEP automatically enables the permissive signal to the High Steam Flow initiation signal associated with Safety Injection as T_{avg} is increasing. The T_{avg}-Low coincident function may be manually blocked as T_{avg} is decreasing. The automatic enabling of the T_{avg}-Low coincident function should occur prior to reaching normal operating temperature (approximately 575°F) since the T_{avg}-Low permissive is required to be OPERABLE concurrent with the High Steam Flow signal for Safety Injection to actuate on a steam line break. Therefore, the Allowable Value for the T_{avg}-Low interlock function is limited on increasing T_{avg}. The Allowable Value associated with ITS Table 3.3.2-1 Function 1.f, High Steam Flow in Two Steam Lines Coincident with T_{avg}-Low, ensures the T_{avg}-Low permissive cannot be manually blocked while RCS temperature is at a point where rapid depressurization on a steam line break could occur.

43 Not used.

44 The CTS requirements for position indication associated with PORVs, PORV Block valves, and the pressurizer safety valves are retained in ITS Table 3.3.3-1 with OPERABILITY requirements for the single channel

is the appropriate surveillance requirement. A generic change has been submitted.

66 ISTS Note 2 to SR 3.3.1.3 is modified to allow 36 hours before SR 3.3.1.3 is required to be performed. Based upon previous plant experience this amount of time is necessary before the NI channels can be adjusted in accordance with the results of a flux map. An approximate time line follows:

TIME (hours)

T=0 Plant power is raised above 15% RTP.

T=7 Plant is stable enough to commence a flux map.

T=10 Flux map is completed.

T=12 The flux map is processed and evaluated to determine that the NI channels are required to be adjusted.

T=17 The flux map(s) for incore/excore calibration is performed.

T=19 Flux map(s) for incore/excore calibration are processed and evaluated.

T=21 I&C Planners have converted incore/excore data into calibration sheets.

T=35 I&C Maintenance technicians install incore/excore calibration.

67 Note (j) is added to Table 3.3.1-1 which modifies the applicability for the source range channel logic inputs to apply only to below the P-6 (intermediate range neutron flux) interlock. The P-6 interlock blocks both the source range detectors and defeats the channel inputs into the actuation logic as well as turin off the detector high voltage supply. With the source range channels blocked, ITS SR 3.3.1.5 cannot be met for source range detector inputs into the actuation logic.

A note is added to SR 3.3.1.5 stating that the SR is not required to be performed for the source range neutron flux detector channels prior to entry into MODE 3 from MODE 2 until 4 hours after antry into MODE 3. This Note allows normal shutdown to proceed without delay for testing in MODE 2 and in MODE 3 until the RTBs are open and SR 3.3.1.5 is no longer required to be performed (i.e., the 4 hour delay allows a norma shutdown to be completed without a required hold on power reduction to perform the testing required by this SR). If the unit is in MODE 3 with the RTBs closed for greater than 4 hours, this SR must be performed prior to 4 hours after entry into MODE 3.

68 In the Tables for ITS 3.3.1 (RPS Instrumentation), ITS 3.3.2 (ESFAS Instrumentation), and ITS 3.3.8 (AFW System Instrumentation), the term "Trip Setpoint" is modified to "Nominal Trip Setpoint" and the inequality signs associated with the Trip Setpoints are removed. These changes are being made for consistency with the CP&L setpoint methodology and the associated discussions in the HBRSEP Unit No. 2 ITS Bases. The setpoint calculations performed for each of the affected setpoints using the CP&L setpoint methodology demonstrate that a channel is OPERABLE if its trip setting, between CHANNEL CALIBRATIONS, exceeds the associated Nominal Trip Setpoint but is within the Allowable Value. The setpoint calculations also demonstrate that if a channel trip setting is within the established calibration tolerance band associated with the Trip Setpoint, no adjustment of the channel's calibration is necessary to ensure the channel is maintained OPERABLE for the length of the CHANNEL CALIBRATION interval. Therefore, the Trip Setpoints are actually "nominal" values rather than "absolute" values. In addition, since these Trip Setpoints are "nominal" values, the inequality signs associated with the Trip Setpoints in the ISTS are not necessary to ensure that the assumptions of the setpoint calculations and OPERABILITY of the associated instrumentation channels are maintained. Notes (2) and (3) are added to allow Nominal Trip Setpoints to be reduced when required by Required Actions.

69 The Note to ISTS LCO 3.3.5 Required Action B.1 is deleted. The bypass capability renders all channels inoperable. Therefore, the associated Diesel Generator would be required to be declared inoperable when the bypass is used.

BASES

BACKGROUND (continued)

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 RTS instrumentation is segmented into four distinct but interconnected modules as illustrated in Figure 1, 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. Signal Process Control and Protection System, including Analog Protection System, Nuclear Instrumentation System (NIS), field contacts, and protection channel sets: 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. Solid State Protection System (SSPS), including input, logic, and output bays: initiates proper unit shutdown and/or ESF actuation 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.

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. To account for the calibration tolerances and instrument drift, which are assumed to occur between calibrations, statistical allowances are provided in the Trip Setpoint and Allowable

(continued)

Supplement 8

BASES

BACKGROUND

Signal Process Control and Protection System (continued)

INSERT B 3.3.1-1

~~prevent the protection function actuation. These requirements are described in IEEE-279-1971 (Ref. 4). The actual number of channels required for each unit parameter is specified in Reference 1.~~ (4)

Two logic channels are required to ensure no single random failure of a logic channel will disable the RTS. The logic channels are designed such that testing required while the reactor is at power may be accomplished without causing trip. ~~Provisions to allow removing logic channels from service during maintenance are unnecessary because of the logic system's designed reliability.~~ (5)

Trip Setpoints and Allowable Values

The ~~Trip Setpoints~~ Nominal are the nominal values at which the bistables are set. Any bistable is considered to be properly adjusted when the "as left" value is within the band for CHANNEL CALIBRATION accuracy (i.e., ± rack calibration + comparator setting accuracy) (110) (in accordance with the Nominal Trip Setpoint) (110)

The ~~Trip Setpoints~~ Nominal used in the bistables are based on the analytical limits stated in Reference ~~1~~ 3. The selection of these Trip Setpoints is such that adequate protection is provided when all sensor and processing time delays are taken into account. To allow for calibration tolerances, instrumentation uncertainties, instrument drift, and severe environment errors for those ~~RTS~~ RPS channels that must function in harsh environments as defined by 10 CFR 50.49 (Ref. ~~5~~ 6), the Trip Setpoints and Allowable Values specified in Table 3.3.1-1 in the accompanying LCO are conservatively adjusted with respect to the analytical limits. A detailed description of the methodology used to calculate the Trip Setpoints, including their explicit uncertainties, is provided in the "RTS/ESFAS Setpoint Methodology Study" (Ref. ~~6~~ 8). The actual Nominal Trip Setpoint entered into the bistable is more conservative than that specified by the Allowable Value to account for changes in random measurement errors detectable by a COT. One example of such a change in measurement error is drift during the surveillance interval. ~~If the measured setpoint does not exceed the Allowable Value, the bistable is considered OPERABLE.~~ (110) (Nominal)

accounted for in setpoint calculations and accident analyses

company setpoint methodology procedure (Ref. 8)

As noted in Table 3.3.1-1 (Note 1), a channel is considered OPERABLE with an actual Trip Setpoint value found outside its "as found" calibration tolerance band provided the Trip Setpoint value is conservative with respect to its associated Allowable Value and the channel is re-adjusted to within the "as left" calibration tolerance band of the Nominal Trip Setpoint. (110) (7)

(continued)

Supplement 8

established calibration tolerance band. A channel is required to be adjusted, if the actual Trip Setpoint is found outside the "as found" calibration tolerance band, such that the actual Trip Setpoint is within the "as left" calibration tolerance band. (110)

The instrument system is designed in accordance with HBRSEP design criteria, which is described in UFSAR Section 3.1 (Ref. 4), and IEEE-279-1968 (Ref. 5).

The instrumentation system is designed such that a failure or malfunction of a control system, that is assumed in the initiation of an accident or transient and concurrently prevents proper action of one or more instrument channels required to mitigate the same accident or transient, will not preclude the proper protection system action. The remaining portions of the instrumentation system are designed to ensure the protection system action occurs to mitigate the accident or transient (i.e., no single failure within the instrumentation system will prevent proper protection system action when required). These requirements are described in Reference 5.

Notes allow Nominal Trip Setpoints to be reduced when required by Required Actions

BASES

BACKGROUND

Trip Setpoints and Allowable Values (continued)

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). Note that in the accompanying LCO 3.3.1, the Trip Setpoints of Table 3.3.1-1 are the LSSS.

Allowable Values

Each channel of the process control equipment can be tested on line to verify that the signal or 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 SRs section.

analog protection system

calculations performed in accordance with the Company Setpoint Methodology Procedure Ref. 8

Into the channel for testing

The Trip Setpoints and Allowable Values listed in Table 3.3.1-1 are based on the methodology described in Reference 6 which incorporates all of the known uncertainties applicable for each channel. The magnitudes of these uncertainties are factored into the determination of each Trip Setpoint. All field sensors and signal processing equipment for these channels are assumed to operate within the allowances of these uncertainty magnitudes.

Nominal

110

the company setpoint methodology procedure (Ref. 8)

Solid State Protection System

Reactor

Relay Logic

This

The SSPS equipment is used for the decision logic processing of outputs from the signal processing equipment bistables. To meet the redundancy requirements, two trains of SSPS, 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.

RPS logic

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

~~this case, the RTS 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 RTS trip and disable one RTS 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 Trip System Functions

The safety analyses and OPERABILITY requirements applicable to each ~~RTS~~ 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 ~~switches~~ 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 the reactor operator to shut down the reactor whenever any parameter is rapidly trending toward its Trip Setpoint. RPS or Engineered Safety Features Actuation System (ESFAS)

The LCO requires two Manual Reactor Trip channels to be OPERABLE. Each channel is controlled by a manual reactor trip ~~switch~~ 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 Control Rod Drive (CRD) System ~~is~~ capable of withdrawing the shutdown rods or the control rods, ~~in this condition,~~ inadvertent control rod withdrawal is

Since withdrawn rods are required to insert to satisfy SDM requirements in these MODES, with the RTBs closed and

in MODE 3, 4, or 5

(continued)

Supplement 8

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1. Manual Reactor Trip (continued)

INSERT B 3.3.1-3

possible. In MODE 3, 4, or 5, manual initiation of a reactor trip does not have to be OPERABLE if the CRD System is not capable of withdrawing the shutdown rods or control rods. If the rods cannot be withdrawn from the core, there is no need to be able to trip the reactor because all of the rods are inserted. 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.

Therefore, manual reactor trip is also required in this condition.

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 the Steam Generator (SG) Water Level Control System. Therefore, the actuation logic must be able 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 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.

Turbine Control System

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.

In MODE 1 or 2, when a positive reactivity excursion could occur, the Power Range Neutron Flux-High trip must be OPERABLE. This Function

(continued)

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

Source Range Neutron Flux (continued)

the Power Range Neutron Flux-Low Setpoint and Intermediate Range Neutron Flux trip Functions. 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 RTS automatic protection function required in MODES 3, 4, and 5. Therefore, the functional capability at the specified Trip Setpoint is assumed to be available.

The LCO requires two channels of Source Range Neutron Flux to be OPERABLE. Two OPERABLE channels are sufficient to ensure no single random failure will disable this trip Function. The LCO also requires one channel of the Source Range Neutron Flux to be OPERABLE in MODE 3, 4, or 5 with RTBs open. In this case, the source range Function is to provide control room indication and input to the Boron Dilution Protection System (BDPS). The outputs of the Function to RTS logic are not required OPERABLE when the RTBs are open.

The Source Range Neutron Flux Function provides protection for control rod withdrawal from subcritical, boron dilution and control rod ejection events. The Function also provides visual neutron flux indication in the control room.

In MODE 2 when below the P-6 setpoint during a reactor startup, 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 Setpoint trip will provide core protection for reactivity accidents. Above the P-6 setpoint, the NIS source range detectors are de-energized and inoperable.

In MODE 3, 4, or 5 with the reactor shut down, the Source Range Neutron Flux trip function must also be OPERABLE. If the CRD System is capable of rod withdrawal, the Source Range Neutron Flux trip must be

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

Power Range Neutron Flux, P-10 (continued)

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.

Turbine Impulse Pressure, P-13

The Turbine Impulse Pressure, P-13 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.

Sends a signal to

The LCO requires two channels of Turbine Impulse Pressure P-13 interlock to be OPERABLE in MODE 1.

The Turbine Impulse Chamber Pressure P-13 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.

electrically loaded

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 RTS logic train that are racked in, closed, and capable of supplying power to the CRD 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 RTS trip capability.

and bypass breaker

RPS

the

RPS

from a single train (when one train is out of service in accordance with LCO 3.3.1 ACTIONS).

with the associated bypass breaker racked out (or removed from the cubicle),

(continued)

Supplement 8

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

Reactor Trip Breakers (continued)

These trip Functions must be OPERABLE in MODE 1 or 2 when the reactor is critical. In MODE 3, 4, or 5, these RTS trip Functions must be OPERABLE when the ~~RTBs or associated bypass breakers are closed, and the~~ CRD System is capable of rod withdrawal (or one or more rods are not fully inserted).

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 CRD System, or declared inoperable under Function 19 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 RTS trip Functions must be OPERABLE when the ~~RTBs and associated bypass breakers are closed, and the~~ CRD System is capable of rod withdrawal (or one or more rods are not fully inserted).

Automatic Trip Logic

The LCO requirement for the RTBs (Functions 19 and 20) and Automatic Trip Logic (Function 21) ensures that means are provided to interrupt the power to allow the rods to fall into the reactor core. Each RTB is equipped with an undervoltage coil and a shunt trip coil to trip the breaker open when needed. Each RTB is equipped with a bypass breaker to allow testing of the trip breaker while the unit is at power. The reactor trip signals generated by the RTS Automatic Trip Logic cause the RTBs and associated bypass breakers to open and shut down the reactor.

The LCO requires two trains of RTS Automatic Trip Logic to be OPERABLE. Having two OPERABLE channels ensures that random failure of a single logic channel will not prevent reactor trip.

(continued)

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The source range channel logic inputs are not required to be OPERABLE above the P-6 interlock

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BASES

1

APPLICABLE SAFETY ANALYSES LCO, and APPLICABILITY

20 81. Automatic Trip Logic (continued)

These trip Functions must be OPERABLE in MODE 1 or 2 when the reactor is critical. In MODE 3, 4, or 5, these RTS trip Functions must be OPERABLE when the RTBs and associated bypass breakers are closed. and the CRD System is capable of rod withdrawal.

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RPS

The RTS instrumentation satisfies Criterion 3 of the NRC Policy Statement.

ACTIONS

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 3.3.1-1.

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.

~~Reviewer's Note: Certain LCO Completion Times are based on approved topical reports. In order for a licensee to use these times, the licensee must justify the Completion Times as required by the staff Safety Evaluation Report (SER) for the topical report.~~

A.1

RPS

Condition A applies to all RTS protection Functions. Condition A addresses the situation where one or more required channels for one or more Functions are inoperable

(continued)

Supplement 8

BASES

SURVEILLANCE REQUIREMENTS (continued)

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.

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 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 SSPS is tested every 31 days on a STAGGERED TEST BASIS, using the semiautomatic tester. The train being tested is placed in the bypass condition, thus preventing inadvertent actuation. Through the semiautomatic tester, all possible logic combinations, with and without applicable permissives, are tested for each protection function. 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.

Insert B3.3-53A

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(ΔI) input to the overtemperature ΔT Function and overpower

(continued)

Insert B3.3-53a

A note is added to SR 3.3.1.5 stating that the SR is not required to be performed for the source range neutron flux detector channels prior to entry into MODE 3 from MODE 2 until 4 hours after antry into MODE 3. This Note allows normal shutdown to proceed without delay for testing in MODE 2 and in MODE 3 until the RTBs are open and SR 3.3.1.5 is no longer required to be performed (i.e., the 4 hour delay allows a norma shutdown to be completed without a required hold on power reduction to perform the testing required by this SR). If the unit is in MODE 3 with the RTBs closed for greater than 4 hours, this SR must be performed prior to 4 hours after entry into MODE 3.

BASES

1

SURVEILLANCE REQUIREMENTS

SR 3.3.1.6 (continued)

A Note modifies SR 3.3.1.6. The Note states that this Surveillance is required only if reactor power is > 50% RTP and that 24 hours is allowed for performing the first surveillance after reaching 50% RTP.

The Frequency of 92 EFPD is adequate. It is based on industry 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.

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. The setpoint shall be left set consistent with the assumptions of the current unit specific setpoint methodology.

(Ref. 8)

The "as found" and "as left" values must also be recorded and reviewed for consistency with the assumptions of Reference 7.

SR 3.3.1.7 is modified by a Note that provides a 4 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 a short time 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 > 4 hours this Surveillance must be performed prior to 4 hours after entry into MODE 3.

The Frequency of 92 days is justified in Reference 7.

122

(i.e., the 4 hour delay allows a normal shutdown to be completed without a required hold on power reduction to perform the testing required by this SR). In addition, performing the COT of the source range instrumentation prior to entry into MODE 3 from MODE 2 may increase the probability of an inadvertent reactor trip.

(continued)

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BASES

1

SURVEILLANCE REQUIREMENTS

SR 3.3.1.9 (continued)

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 every [18] 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.

CHANNEL CALIBRATIONS must be performed consistent with the assumptions of the unit specific setpoint methodology. 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. 6 (Ref. 8)

The Frequency of 18 months is based on the assumption of an 18 month calibration interval in 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. 39

This Note applies to those Functions equipped with electronic dynamic compensation. Not all Functions to which SR 3.3.1.10 is applicable are equipped with electronic dynamic compensation

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 [18] months. This SR is modified by a Note stating that neutron detectors are excluded from the CHANNEL CALIBRATION. 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

(continued)

Supp. 8

BASES

REFERENCES (continued)

5. 10 CFR 50.49.

6. RTS/ESFAS Setpoint Methodology Study.

7. WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990.

8. Technical Requirements Manual, Section 15, "Response Times."

Insert B 3.3-60A

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Insert B3.3-60A

8. Attachment VIII to CPL's letter to NRC dated May 30, 1997, H. B. Robinson Steam Electric Plant, Unit No. 2 - Response to Request for Additional Information and Transmittal of Supplement 4 Regarding the Technical Specification Change Request to Convert to the Improved Standard Technical Specification.

1

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: ~~Solid State Protection System (SSPS) including input logic, and output bays:~~ ~~initiates the proper unit~~ shutdown or 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. 3

Field Transmitters or Sensors

To meet the design demands for redundancy and reliability, more than one, and often as many as ~~four~~ three, 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 ~~Trip~~ Protection System (~~RTS~~ 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~~ Nominal 110

(continued)

Supplement 8

BASES

BACKGROUND Signal Processing Equipment (continued)

actuation. Again, a single failure will neither cause nor prevent the protection function actuation.

These requirements are described in IEEE-279-1971 (Ref. 4). The actual number of channels required for each unit parameter is specified in Reference 2.

Trip Setpoints and Allowable Values

The Trip Setpoints are the nominal values at which the bistables are set. Any bistable is considered to be properly adjusted when the "as left" value is within the band for CHANNEL CALIBRATION accuracy.

The Trip Setpoints used in the bistables are based on the analytical limits stated in Reference 2. The selection of these Trip Setpoints is such that adequate protection is provided when all sensor and processing time delays are taken into account. To allow for calibration tolerances, instrumentation uncertainties, instrument drift, and severe environment errors for those ESFAS channels that must function in harsh environments as defined by 10 CFR 50.49 (Ref. 5), the Trip Setpoints and Allowable Values specified in Table 3.3.2-1 in the accompanying LCO are conservatively adjusted with respect to the analytical limits. A detailed description of the methodology used to calculate the Trip Setpoints, including their explicit uncertainties, is provided in the "RTS/ESFAS Setpoint Methodology Study" (Ref. 6). The actual nominal Trip Setpoint entered into the bistable is more conservative than that specified by the Allowable Value to account for changes in random measurement errors detectable by a COT. One example of such a change in measurement error is drift during the surveillance interval. If the measured setpoint does not exceed the Allowable Value, the bistable is considered OPERABLE.

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.

As noted in Table 3.3.2-1 (Note 1), a channel is considered OPERABLE with an actual Trip Setpoint value found outside its "as found" calibration tolerance band provided the Trip Setpoint value is conservative with respect to its associated Allowable Value and the channel is re-adjusted to within the "as left" calibration tolerance band of the Nominal Trip Setpoint.

(continued)

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(in accordance with the Nominal Trip Setpoint)

(Nominal)

(Nominal)

accounted for in setpoint calculations and accident analyses

(Nominal)

company setpoint methodology procedure (Ref. 9)

established calibration tolerance band. A channel is required to be adjusted, if the actual Trip Setpoint is found outside the "as found" calibration tolerance band, such that the actual Trip Setpoint is within the "as left" calibration tolerance band.

1 4 6 7 110

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 do not provide control functions; therefore the two-out-of-three logic is adequate to provide the required protection.

1

BASES

BACKGROUND

Trip Setpoints and Allowable Values (continued)

Calculations performed in accordance with the company setpoint methodology procedure (Ref. 9).

Each channel 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.

Nominal 110

the company setpoint methodology procedure (Ref. 9)

The Trip Setpoints and Allowable Values listed in Table 3.3.2-1 are based on the methodology described in Reference 6, which incorporates all of the known applicable uncertainties applicable for each channel. The magnitudes of these uncertainties are factored into the determination of each Trip Setpoint. All field sensors and signal processing equipment for these channels are assumed to operate within the allowances of these uncertainty magnitudes.

Nominal 110

ESFAS Automatic Initiation Logic

Solid State Protection System

3

ESFAS relay logic

The SSPS equipment is used for the decision logic processing of outputs from the signal processing equipment bistables. To meet the redundancy requirements, two trains of SSPS 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. 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.

41

3

The SSPS 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 of the unit.

3

relay logic

The bistable outputs from the signal processing equipment are sensed by the SSPS equipment and combined into logic matrices that represent combinations indicative of various

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

b. Safety Injection – Automatic Actuation Logic and Actuation Relays (continued)

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 to support ~~system level manual initiation~~ OPERABILITY of the and Containment Pressure – High Functions

In addition, the Containment Pressure – High Function is required to be OPERABLE in MODE 4 since there may be sufficient energy in the primary or secondary systems to pressurize the containment following a pipe break. Therefore,

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. Safety Injection – Containment Pressure – High

This signal provides protection against the following accidents:

- SLB inside containment;
- LOCA; and
- Feed line break inside containment.

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.

Thus, the high pressure Function will not experience any adverse environmental conditions and the Trip Setpoint reflects only steady state instrument uncertainties.

(continued)

Supplement 8

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

e. Steam Line Pressure – High Differential Pressure Between Steam Lines (continued)

- Inadvertent opening of an SG relief or an SG safety valve.

Steam Line Pressure – 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 typically located inside the steam tunnels, it is possible for them to experience adverse environmental conditions during an SLB event. Therefore, the Trip Setpoint reflects only 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. Safety Injection – High Steam Flow in Two Steam Lines Coincident With T_{avg} – Low Low or Coincident With Steam Line Pressure – Low

These Functions (1.f and 1.g) provide protection against the following accidents:

- SLB; and
- the inadvertent opening of an SG relief or an 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-

(continued)

Supplement 8

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

c. Steam Line Isolation – Containment Pressure – High 2 (continued)

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 and (de-activated). 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 2 setpoint.

d. Steam Line Isolation – Steam Line Pressure

(1) Steam Line Pressure – Low

Steam Line Pressure – Low provides closure of the MSIVs in the event of an SLB to maintain at least one unfaulted SG as a heat sink for the reactor, and to limit the mass and energy release to containment. This Function provides closure of the MSIVs in the event of a feed line break to ensure a supply of steam for the turbine driven AFW pump. Steam Line Pressure – Low was discussed previously under SI Function 1.e.1.

Steam Line Pressure – Low Function must be OPERABLE in MODES 1, 2, and 3 (above P-11), with any main steam valve open, when a secondary side break or stuck open valve could result in the rapid depressurization of the steam lines. This signal may be manually blocked by the operator below the P-11 setpoint. Below P-11, an inside containment SLB will be terminated by automatic actuation via Containment Pressure – High 2. Stuck valve transients and outside containment SLBs will be terminated by the Steam Line Pressure – Negative Rate – High signal for Steam Line Isolation below P-11 when SI has been manually blocked. The Steam Line Isolation Function is required in MODES 2

(continued)

Supplement 8

BASES

INSERT B3.3-106A

ACTIONS

C.1, C.2.1 and C.2.2 (continued)

- Phase B Isolation; and
- Automatic Switchover to Containment Sump.

The 12 hour Completion Time provides adequate time to perform maintenance or repairs to the automatic actuation logic and actuation relays.

This action addresses the train orientation of the SSPS 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.

Supplement 7

~~The Required Actions are modified by a Note that allows one train to be bypassed for up to [4] 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. 8) that 4 hours is the average time required to perform channel surveillance.~~

D.1, D.2.1, and D.2.2

Condition D applies to:

- ~~Containment Pressure – High 1;~~
- Pressurizer Pressure – Low ~~(two, three, and four loop units)~~;
- ~~Steam Line Pressure – Low;~~
- Steam Line Differential Pressure – High;
- High Steam Flow in Two Steam Lines Coincident With T_{avg} – Low ~~Low~~ or Coincident With Steam Line Pressure – Low; and

Supplement 3

(continued)

Insert B3.3-106A

Due to the plant design, maintenance of a single channel can not be performed without causing all channels of the associated Function to be inoperable. In many cases, maintenance will also cause the associated train to be inoperable.

For repair or replacement of Engineered Safeguard System relays and/or test switches, 12 hours is a reasonable Completion Time for restoration of the two most frequently occurring types of failures that occur in the HBRSEP Unit No. 2 Engineered Safeguards System. These two failures are 1) failure of a logic or actuation relay, and 2) failure of the test switches used for the performance of the surveillance testing. A failure of either of these items only causes one portion of the Engineered Safeguards System to be inoperable, but due to the wiring configuration of the system (the common side of the relay power source is "daisy chained" together) the entire train must be considered inoperable once maintenance on the failed item has commenced.

The allowed time of 12 hours for inoperability of a single train on an ESFAS instrumentation train is considered to be acceptable based on the fact that the other ESFAS instrumentation train is available to perform the actuation function and the low probability of an event requiring an ESFAS actuation. In addition, the change provides the potential benefit of the avoidance of a plant shutdown transient by providing a time period to perform required surveillance testing or necessary maintenance prior to requiring a plant shutdown.

BASES

ACTIONS D.1, D.2.1, and D.2.2 (continued)

Steam Line Isolation

- Containment Pressure – High 2 High. 110
- Steam Line Pressure – Negative Rate – High;
- High Steam Flow Coincident With Safety Injection Coincident With T_{avg} – Low Low;
- High High Steam Flow Coincident With Safety Injection;
- High Steam Flow in Two Steam Lines Coincident With T_{avg} – Low Low; 51
- SG Water level – Low Low (two, three, and four loop units); and
- [SG Water level – High High (P-14) (two, three, and four loop units).]

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-~~three~~ two configuration that satisfies redundancy requirements.

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 [4] 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 4 hours allowed for testing, are justified in Reference 8.~~ 77

(continued)

Supplement 8

110

Insert B3.3-110A

BASES

ACTIONS (continued)

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 [, Turbine Trip and Feedwater Isolation] and AFW actuation Functions.

The action addresses the train orientation of the SSPS and the master and slave relays for these functions. If one train is inoperable, 8 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. 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.

The 12 hour Completion Time provides adequate time to perform maintenance or repairs to the automatic actuation logic and actuation relays.

Supplement 7

The Required Actions are modified by a Note that allows one train to be bypassed for up to [4] hours for surveillance testing provided the other train is OPERABLE. This allowance is based on the reliability analysis (Ref. 8) assumption that 4 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 Turbine Trip and Feedwater Isolation Function.

This action addresses the train orientation of the SSPS and the master and slave 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. The Completion Time for restoring a train to OPERABLE status is reasonable considering that there is another train OPERABLE, and the low probability of

(continued)

Insert B3.3-110A

Due to the plant design, maintenance of a single channel can not be performed without causing all channels of the associated Function to be inoperable. In many cases, maintenance will also cause the associated train to be inoperable.

For repair or replacement of Engineered Safeguard System relays and/or test switches, 12 hours is a reasonable Completion Time for restoration of the two most frequently occurring types of failures that occur in the HBRSEP Unit No. 2 Engineered Safeguards System. These two failures are 1) failure of a logic or actuation relay, and 2) failure of the test switches used for the performance of the surveillance testing. A failure of either of these items only causes one portion of the Engineered Safeguards System to be inoperable, but due to the wiring configuration of the system (the common side of the relay power source is "daisy chained" together) the entire train must be considered inoperable once maintenance on the failed item has commenced.

The allowed time of 12 hours for inoperability of a single train on an ESFAS instrumentation train is considered to be acceptable based on the fact that the other ESFAS instrumentation train is available to perform the actuation function and the low probability of an event requiring an ESFAS actuation. In addition, the change provides the potential benefit of the avoidance of a plant shutdown transient by providing a time period to perform required surveillance testing or necessary maintenance prior to requiring a plant shutdown.

I.1, 1.2.1, I.2.2, and I.2.3

Condition I applies to manual initiation function of Containment Spray and Phase B Isolation.

This action addresses the train orientation of the relay logic for the function. With one or more of the Containment Spray Manual Initiation pushbuttons inoperable, there is no means available to manually initiate Containment Spray or Phase B Containment Isolation through the automatic actuation relays. The Manual Initiation is set up on two-out-of-two logic, with only two pushbuttons provided, and a single failure of either of the pushbuttons renders the entire Manual Initiation function inoperable. Therefore, if a channel or train is inoperable, it must be returned to OPERABLE status within 1 hour. The 1 hour Completion Time is equal to the time allowed by LCO 3.0.3 to initiate shutdown actions in the event of a complete loss of ESFAS function. If the channel is not returned to OPERABLE status within the 1 hour Completion Time, the unit must be placed in MODE 3 within the next 6 hours, in MODE 4 within the following 6 hours, and in MODE 5 within the following 24 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 5 removes all requirements for OPERABILITY of this function.

ITS Insert B 3.3.2-13a (ESFAS Instrumentation)

The Surveillances are also modified by Note 2 to indicate that when a channel is placed in an inoperable status solely for the performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the redundant ESFAS train is OPERABLE. Upon completion of the Surveillance or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and the Required Actions performed. If maintenance is to be subsequently performed as a result of a failed surveillance test, LCO 3.3.2 ACTIONS are applicable. Note 2 to the Surveillance Requirements is based on operating history which has shown that 6 hours is generally the time required to perform the channel surveillance with additional time to allow for short term plant changes or verification of any abnormal responses. This 6 hour testing allowance does not significantly reduce the probability that the ESFAS will initiate when necessary.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.2.3 (continued)

tester is not used and the continuity check does not have to be performed, as explained in the Note. This SR is applied to the balance of plant actuation logic and relays that do not have the SSPS test circuits installed to utilize the semiautomatic tester or perform the continuity check. This test is also performed every 31 days on a STAGGERED TEST BASIS. The Frequency is adequate based on industry operating experience, considering instrument reliability and operating history data.

SR 3.3.2.4

SR 3.3.2.4 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 is injected 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 (4 hours) and the surveillance interval are justified in Reference 8.

INSERT B 3.3.2-14

SR 3.3.2.5

SR 3.3.2.5 is the performance of a COT.

INSERT B 3.3.2-15

A COT is performed on each required channel to ensure the entire channel will perform the intended Function. Setpoints must be found within the Allowable Values specified in Table 3.3.2-1.

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.

The "as found" and "as left" values must also be recorded and reviewed for consistency with the assumptions of the

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.8

SR 3.3.2.8 is the performance of a TADOT. This test is a check of the Manual Actuation Functions and AFW pump start on trip of all MFW pumps. It is performed every 18 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 3.3.2.9

SR 3.3.2.9 is the performance of a CHANNEL CALIBRATION.

A CHANNEL CALIBRATION is performed every 18 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. 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 Frequency of 18 months is based on the assumption of an 18 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.

SR 3.3.2.10

This SR ensures the individual channel ESF RESPONSE TIMES are less than or equal to the maximum values assumed in the

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.2.11 (continued)

Trip Interlock, and the Frequency is once per RTB cycle. This Frequency is based on operating experience demonstrating that undetected failure of the P-4 interlock sometimes occurs when the RTB is cycled.

The SR is modified by a Note that excludes verification of setpoints during the TADOT. The Function tested has no associated setpoint.

REFERENCES

1. FSAR, Chapter 6.
2. FSAR, Chapter 7.
3. FSAR, Chapter 15.
4. UFSAR, Section 3.1
5. IEEE-279-1971.
6. 10 CFR 50.49.
7. UFSAR, Section 6.2.4.
8. WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990.
9. Technical Requirements Manual, Section 15, "Response Times."

INSERT B 3.3.2-17

Insert B3.3.2-17

9. Attachment VIII to CPL's letter to NRC dated May 30, 1997, H. B. Robinson Steam Electric Plant, Unit No. 2 - Response to Request for Additional Information and Transmittal of Supplement 4 Regarding the Technical Specification Change Request to Convert to the Improved Standard Technical Specification.

Trip Setpoints and tolerances are specified for each Function in the LCO. If the measured setpoint falls within the tolerance band, the relay is considered OPERABLE. Operation with a measured setpoint less conservative than the Trip Setpoint, but within the tolerance band, is acceptable provided that operation and testing is consistent with the assumptions of the setpoint calculation. Each Trip Setpoint specified is more conservative than the analytical values determined in Reference 2 in order to account for instrument uncertainties appropriate to the trip function. These uncertainties are defined in the company setpoint methodology procedure (Ref. 4).

The dropout time delay on the loss of voltage relays is very short, almost instantaneous. This short time delay is necessary to preclude damage to equipment from operating on less than minimum manufacturer's recommended voltage for continuous motor operation. The dropout time delay on the degraded voltage relays is significantly longer. A long time delay is desired such that it will minimize the effects of short duration disturbances on the grid. However, the allowable time duration of a degraded voltage condition must be short enough that it will not result in failure of safety systems or components.

BASES

ACTIONS (continued)

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~~ are tracked separately for each Function starting from the time the Condition was entered for that Function.

INSERT B 3.3.5-5

B A.1

Condition A applies to the LOP DG start Function with one ~~loss of voltage or~~ degraded voltage channel per bus inoperable.

If one of the three channel~~s~~ is inoperable, Required Action B.1 ~~A.1~~ requires that channel to be placed in trip within 6 hours. With a channel in trip, the LOP DG start instrumentation channels are then configured to provide a one-out-of-~~three~~ two logic to initiate a trip of the incoming offsite power.

~~A Note is added to allow bypassing an inoperable channel for up to 4 hours for surveillance testing of other channels. This allowance is made where bypassing the channel does not cause an actuation and where at least two other channels are monitoring that parameter.~~

The specified Completion Time and time allowed for bypassing one channel are reasonable considering the Function remains fully OPERABLE on every bus and the low probability of an event occurring during these intervals.

B.1 C

Condition B applies when ~~more than one loss of voltage or~~ more than one degraded voltage channel on a single bus is inoperable.

Required Action B.1 C.1 requires restoring all but one channel on each bus to OPERABLE status. The 1 hour Completion Time should allow ample time to repair most failures and takes into account the low probability of an event requiring an LOP start occurring during this interval.

(continued)

Supplement 8

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.5.~~2~~ 1

SR 3.3.5.~~2~~ is the performance of a TADOT. This test is performed every ~~31 days~~ 18 months. The test checks trip devices that provide actuation signals directly, bypassing the analog process control equipment. ~~For these tests, the relay trip setpoints are verified and adjusted as necessary.~~ 110 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.

The SR is modified by a Note that excludes verification of the setpoint from the TADOT. Setpoint verification is accomplished during the CHANNEL CALIBRATION.

SR 3.3.5.~~3~~ 2

SR 3.3.5.~~3~~ 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~~ should include a single point verification that the trip occurs within the required time delay, as shown in Reference 1. 106

A CHANNEL CALIBRATION is performed every ~~18~~ 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. 110

The Frequency of ~~18~~ months is based on operating experience and consistency with the typical industry refueling cycle and is justified by the assumption of an ~~18~~ month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

REFERENCES

1. FSAR, Section ~~8.3~~. 4
2. FSAR, Chapter ~~15~~. 5 INSERT B 3.3.5-6
3. ~~Unit Specific RTS/ESFAS Setpoint Methodology Study~~

Insert B 3.3-5-6A 6

Supplement 8

ITS Insert B 3.3.5-6 (LOP DG Start Instrumentation)

2. CP&L Letter to NRC, Serial No. GD-79-2502, dated October 5, 1979, transmitting summary of "Degraded Grid Voltage Study for H.B. Robinson Unit No. 2," Ebasco Services, Incorporated, October 15, 1976

ITS Insert B 3.3.5-6A

4. Attachment VIII to CPL's letter to NRC dated May 30, 1997, H. B. Robinson Steam Electric Plant, Unit No. 2 - Response to Request for Additional Information and Transmittal of Supplement 4 Regarding the Technical Specification Change Request to Convert to the Improved Standard Technical Specification.

BASES

LCO (continued)

2. Automatic Actuation Logic and Actuation Relays (Supplement 7) (Supplement 8) (1) (to be) (34)

The LCO requires two trains of Automatic Actuation Logic and Actuation Relays OPERABLE to ensure that no single random failure can prevent automatic actuation. (108)

INSERT B 3.3.6-2

~~Automatic Actuation Logic and Actuation Relays consist of the same features and operate in the same manner as described for ESFAS Function 1.b, SI, and ESFAS Function 3.a, Containment Phase A Isolation. The applicable MODES and specified conditions for the containment purge isolation portion of these Functions are different and less restrictive than those for their Phase A isolation and SI roles. If one or more of the SI or Phase A isolation Functions becomes inoperable in such a manner that only the Containment Purge Isolation Function is affected, the Conditions applicable to their SI and Phase A isolation Functions need not be entered. The less restrictive Actions specified for inoperability of the Containment Purge Isolation Functions specify sufficient compensatory measures for this case.~~

3. Containment Radiation

The LCO specifies ~~four~~ two required channels of radiation monitors to ensure that the radiation monitoring instrumentation necessary to initiate Containment ~~Purge~~ Ventilation Isolation remains OPERABLE.

For sampling systems, 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.

4. ~~Containment Isolation - Phase A~~ Safety Injection (Supplement 7)

Refer to LCO 3.3.2, Function ~~3.a~~ 1.a-f, for all initiating Functions and requirements.

(continued)

B 3.3.8 Auxiliary Feedwater (AFW) System Instrumentation

BASES

BACKGROUND

The AFW System automatically supplies feedwater to the steam generators (SGs) to remove decay heat from the Reactor Coolant System (RCS) upon loss of normal feedwater supply. The AFW System can provide feedwater to the SGs from any one or combination of three AFW pumps, two of which are motor driven and the third of which is steam turbine driven.

The two motor driven AFW pumps are powered from emergency busses E-1 and E-2. These busses also supply power to the motor driven AFW pump discharge isolation valves and the turbine driven AFW pump steam supply and feedwater discharge isolation valves. The turbine driven AFW pump provides a second independent and diverse means of providing auxiliary feedwater to the SGs.

Initiation of an automatic actuation signal to the turbine driven AFW pump causes the turbine steam supply valves and the pump feedwater discharge isolation valves to open. An automatic actuation signal to the motor driven AFW pumps cause the pumps to become energized and accelerate up to speed, and the feedwater discharge isolation valves to open.

Two trains of AFW actuation relay logic are used to develop the coincident signals from the process inputs. Logic train A starts one motor driven AFW pump and Logic train B starts the second motor driven AFW pump. Each logic train independently actuates the turbine driven AFW pump.

The AFW automatic actuation instrumentation is discussed in UFSAR Section 7.3.1 (Ref. 1). The instrumentation is designed in accordance with HBRSEP design criteria, which is described in UFSAR Section 3.1 (Ref. 2).

Trip Setpoints and Allowable Values

The Nominal Trip Setpoints are the nominal values at which the bistables are set. Any bistable is considered to be properly adjusted (in accordance with the Nominal Trip Setpoint when the "as left" value is within the established calibration tolerance band. A channel is required to be adjusted, if the actual Trip Setpoint is found outside the "as found" calibration tolerance band, such that the actual Trip Setpoint is within the "as left" calibration tolerance band.

B 3.3.8 Auxiliary Feedwater (AFW) System Instrumentation

BASES

BACKGROUND (continued)

The Nominal Trip Setpoints used in the bistables are based on the analytical limits or design limits. The selection of these Nominal Trip Setpoints is such that adequate protection is provided when all sensor and processing time delays accounted for in setpoint calculations and accident analyses are taken into account. To allow for calibration tolerances, instrumentation uncertainties, instrument drift, and severe environment errors for those channels that must function in harsh environments as defined by 10 CFR 50.49, the Nominal Trip Setpoints and Allowable Values specified in Table 3.3.8-1 in the accompanying LCO are conservatively adjusted with respect to the analytical limits. A detailed description of the methodology used to calculate the Nominal Trip Setpoints, including their explicit uncertainties, is provided in the company setpoint methodology procedure (Ref. 4). The actual Nominal Trip Setpoint entered into the bistable is more conservative than that specified by the Allowable Value to account for changes in random measurement errors detectable by a COT. One example of such a change in measurement error is drift during the surveillance interval. As noted in Table 3.3.8-1 (Note 1), a channel is considered OPERABLE with an actual Trip Setpoint value found outside its "as found" calibration tolerance band provided the Trip Setpoint Value is conservative with respect to its Allowable Value and the channel is re-adjusted to within the "as left" calibration tolerance band of the Nominal Trip Setpoint.

Setpoints in accordance with the Allowable Value ensure that the consequences of Design Basis Accidents (DBAs) and transients will be acceptable, providing the unit is operated from within the LCOs at the onset of the DBA or transient and the equipment functions as designed.

Each channel can be tested on line to verify that the signal processing equipment and setpoint accuracy is within the specified allowance requirements of calculations performed in accordance with the company setpoint methodology procedure (Ref. 4). 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.

B 3.3.8 Auxiliary Feedwater (AFW) System Instrumentation

BASES

BACKGROUND (continued)

The Nominal Trip Setpoints and Allowable Values listed in Table 3.3.8-1, are based on the methodology described in the company setpoint methodology procedure (Ref. 4), which incorporates all of the applicable uncertainties for each channel. The magnitudes of these uncertainties are factored into the determination of each Nominal Trip Setpoint. All field sensors and signal processing equipment for these channels are assumed to operate within the allowances of these uncertainty magnitudes.

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 SGs to remove decay heat and other residual heat by delivering at least the minimum required flow rate to the SGs at pressures corresponding to the lowest main steam safety valve (MSSV) set pressure plus 3%.

In addition, the AFW System must supply enough makeup water to replace SG secondary inventory lost as the unit cools to MODE 4 conditions. Sufficient AFW flow must also be available to account for flow losses such as pump recirculation and line breaks.

The limiting Design Basis Accidents (DBAs) and transients for the AFW System are as follows:

a. Feedwater Line Break (FWLB); and

b. Loss of main feedwater (MFW).

In addition, the minimum available AFW flow and system characteristics are serious considerations in the analysis of a small break loss of coolant accident (LOCA).

The AFW System design is such that, in the event of a complete loss of offsite power, decay heat removal would continue to be assured by the availability of either the turbine driven AFW pump, or one of the two motor driven AFW pumps, along with steam discharge to the atmosphere through the MSSVs.

The AFW System actuation instrumentation satisfies Criterion 3 of the NRC Policy Statement.

B 3.3.8 Auxiliary Feedwater (AFW) System Instrumentation

BASES

LCO

This LCO provides assurance that the AFW System will perform its design safety function to mitigate the consequences of accidents that could result in overpressurization of the reactor coolant pressure boundary.

The LCO requires all instrumentation performing an AFW System actuation function to be OPERABLE. Failure of any instrument renders the affected channel(s) inoperable and reduces the reliability of the affected Functions.

The required channels of AFW System actuation instrumentation provide unit protection in the event of any of the analyzed accidents. AFW System actuation instrumentation protection functions are as follows:

1. Steam Generator Water Level-Low Low

   SG Water Level – Low Low provides protection against a loss of heat sink. A feed line break, inside or outside of containment, or a loss of MFW, would result in a loss of SG water level. SG Water Level – Low Low provides input to the SG Level Control System. Two-out-of-three signals on one SG will start the motor driven AFW pumps. Two-out-of-three signals on two SGs will start the steam driven AFW pump. Thus, three OPERABLE channels are required to satisfy the requirements with two-out-of-three logic.

2. Safety Injection (SI)

   An SI signal starts the two motor driven AFW pumps. The AFW initiation functions are the same as the requirements for their SI function. Therefore, the

LCO

2. Safety Injection (SI) (continued)

requirements are not repeated in Table 3.3.8-1. Instead, Table 3.3.2-1, Function 1 (Safety Injection), is referenced for all initiating functions and requirements.

3. Loss of Offsite Power

A loss of offsite power to the 480 V emergency busses will be accompanied by a loss of MFW and reactor coolant pumping power, and the subsequent need for some method of decay heat removal. Loss of offsite power is detected by undervoltage relays sensing the voltage on each 480 volt emergency (E) bus. Loss of power to either emergency bus will start the motor driven AFW pumps in the station blackout loading sequence 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. A loss of power to the E1 bus initiates a start of the "A" AFW pump and a loss of power to the E2 bus initiates a start of the "B" AFW pump. The relays are arranged in a one-out-of-two logic, such that either relay will generate a loss of power (LOP) signal if the voltage is below the setpoint for a short period of time. The LOP signal also initiates starting the emergency diesel generators as described in the bases to LCO 3.3.5, "Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation."

4. Undervoltage- Reactor Coolant Pump (RCP)

A loss of power on 4 kV buses 1 and 4, which provide power to both MFW pumps and two RCPs, provides indication of a loss of MFW and forced flow in the RCS. Two sensors are provided on each bus, with two-out-of-two logic on both busses required to start the turbine driven AFW pump 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.

B 3.3.8 Auxiliary Feedwater (AFW) System Instrumentation

BASES

LCO (continued)

5. Trip of All Main Feedwater Pumps

A Trip of both MFW pumps is an indication of a loss of MFW and the subsequent need for some method of decay heat and sensible heat removal to bring the reactor back to no load temperature and pressure conditions. One contact on each MFW pump circuit breaker position provides input to the actuation logic that starts the motor driven AFW pumps. A trip of both MFW pumps starts the two motor driven AFW pumps to ensure that at least one SG is available with water to act as the heat sink for the reactor.

APPLICABILITY

Functions 1 through 4 must be OPERABLE in MODES 1, 2, and 3 to ensure that the SGs remain the heat sink for the reactor. 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 automatic 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 will be available to manually place either system in operation.

Function 5 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 an accident. In MODES 3, 4, and 5, the MFW pumps may be normally shut down, and thus neither pump trip is indicative of a condition requiring automatic AFW actuation.

B 3.3.8 Auxiliary Feedwater (AFW) System Instrumentation

BASES

ACTIONS

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 on Table 3.3.8-1.

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 Function(s) affected. When the Required Channels in Table 3.3.8-1 are specified (e.g., on a per bus or per pump basis), then the Condition may be entered separately for each bus or pump, etc., as appropriate.

A.1

Condition A applies to all AFW Functions, and 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 3.3.8-1 and to take the Required Actions for the 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 Undervoltage-Reactor Coolant Pump. If one channel is inoperable, 4 hours are allowed to restore the channel to OPERABLE status or to place it in the tripped condition. A failure of one Undervoltage-Reactor Coolant Pump channel places the Function in an unacceptable configuration. The inoperable channel must be tripped to place the Function in a one-out-of-one coincident with a two-out-of-two configuration.

ACTIONS

B.1, B.2.1, and B.2.2 (continued)

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.

C.1, C.2.1, and C.2.2

Condition C applies to 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. A failure of one SG Water Level-Low Low 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.

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.

D.1, D.2.1, and D.2.2

Condition D applies to Loss of Offsite Power. This action recognizes the lack of manual trip provision for a failed channel. If a channel is inoperable, 48 hours are allowed to return it to OPERABLE status. The specified Completion Time is reasonable considering the nature of this Function, the available redundancy, and the low probability of an event occurring during this interval. If the Function cannot be returned to OPERABLE status, the unit must be

B 3.3.8 Auxiliary Feedwater (AFW) System Instrumentation

BASES

ACTIONS

D.1, D.2.1, and D.2.2 (continued)

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.

E.1 and E.2

Condition E applies to the AFW pump start on trip of all MFW pumps. This action addresses the relay logic for the auto start function of the AFW System on loss of all MFW pumps. The OPERABILITY of the AFW System must be assured by allowing automatic start of the AFW System pumps. If a channel is inoperable, 48 hours are allowed to return it to an OPERABLE status. If the Function cannot be returned to an OPERABLE status, 6 hours are allowed 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. The allowance of 48 hours to return the train to an OPERABLE status is justified in WCAP-10271-P-A (Ref. 3).

SURVEILLANCE REQUIREMENTS

The SRs for each AFW Actuation Function are identified by the SRs column of Table 3.3.8-1.

A Note has been added to the SR Table to clarify that Table 3.3.8-1 determines which SRs apply to which Functions.

The CHANNEL CALIBRATION and COTs are performed in a manner that is consistent with the assumptions used in analytically calculating the required channel accuracies.

B 3.3.8 Auxiliary Feedwater (AFW) System Instrumentation

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.8.1

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 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.

Channel deviation 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, but more frequent, checks of channels during normal operational use of the displays associated with the LCO required channels.

SR 3.3.8.2

SR 3.3.8.2 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

SURVEILLANCE REQUIREMENTS

SR 3.3.8.2 (continued)

within the tolerances and Allowable Values specified in Table 3.3.8-1.

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 (Ref. 4). The setpoint must be left set consistent with the assumptions of the setpoint methodology (Ref. 4).

The "as found" and "as left" values must also be recorded and reviewed for consistency with the assumptions of the surveillance interval extension analysis in Reference 3 when applicable.

The Frequency of 92 days is justified in Reference 3.

SR 3.3.8.3

SR 3.3.8.3 is the performance of a TADOT. This test is a check of AFW pump automatic start on loss of offsite power, undervoltage RCP, and trip of all MFW pumps Functions. It is performed every 18 months. Each applicable Actuation Function is tested up to, and including, the end device start circuitry. In some instances, the test includes actuation of the end device (i.e., pump starts, valve cycles, etc.). As noted, this SR requires the injection of a simulated or actual signal for the Trip of Main Feedwater Pumps Function. The injection of the signal should be as close to the sensor as possible. The Frequency is adequate, based on industry operating experience and is consistent with the typical refueling cycle.

SR 3.3.8.4

SR 3.3.8.4 is the performance of a CHANNEL CALIBRATION. A CHANNEL CALIBRATION is performed every 18 months, or

B 3.3.8 Auxiliary Feedwater (AFW) System Instrumentation

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.8.4 (continued)

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. 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 Frequency of 18 months is based on the assumption of an 18 month calibration interval in the determination of the magnitude of equipment drift in the setpoint methodology.

REFERENCES

1. UFSAR, Section 7.3.1

2. UFSAR, Section 3.1

3. WCAP-10271-P-A, Supplement 2, Rev. 1., June 1990

4. Attachment VIII to CPLs letter to NRC dated May 30, 1997, H. B. Robinson Steam Electric Plant, Unit No. 2 - Response to Request for Additional Information and Transmittal of Supplement 4 Regarding the Technical Specification Change Request to Convert to the Improved Standard Technical Specification.

1 In the conversion of the HBRSEP current Technical Specifications (CTS) to the proposed plant specific Improved Technical Specifications (ITS), certain wording preferences or conventions are adopted which do not result in technical changes (either actual or interpretational). Editorial changes which involve the insertion of plant specific terms or parameters are used to preserve consistency with the CTS and licensing basis.

2 Bases 3.3.1 are modified to reflect a title change from "Reactor Trip System (RTS)," to "Reactor Protection System (RPS)," to be consistent with plant terminology and original licensing basis. Reference to the Specification title are modified throughout, accordingly.

3 Bases 3.3.1 and 3.3.2 are modified to reflect that the plant design basis does not include a Solid State Protection System (SSPS), as described in NUREG-1431, but instead is equipped with Reactor Protection System (RPS) and Engineered Safety Features Actuation System (ESFAS) relay logic, which is the analog equivalent to SSPS.

4 Reactor trip and engineered safety features instrumentation systems were designed in accordance with IEEE-279-1968, which did not stipulate specific logic matrices for functions where a channel is shared by control and protection. Therefore, design of the instrumentation systems does not provide 2 out of 4 logic in all cases where a channel is shared by both control and protection. In addition, when a 2 out of 4 logic is provided, it is not necessarily for the purpose of reducing and protecting against control-protection interactions. IEEE-279-1968 does specify (in Section 4.7) that the RPS meet single failure criteria when a channel feeding control circuits is inoperable in a non-conservative state.

5 Plant design is such that logic channels must be removed from service for testing and maintenance.

6 Trip Setpoints and Allowable Values are determined in accordance with the company setpoint methodology procedure. This procedure is based on NRC approved setpoint methodologies. The setpoint methodology was provided to NRC as Attachment VIII to CPL's letter to NRC dated May 30, 1997, H. B. Robinson Steam Electric Plant, Unit No. 2 - Response to Request for Additional Information and Transmittal of Supplement 4 Regarding the Technical Specification Change Request to Convert to the Improved Standard Technical Specification.

7 The term "bistable" is changed to "channel" to clarify the subpart of the function that would be inoperable. In the performance of the COT, any piece of signal process equipment which makes up a channel may render the channel inoperable, not just the bistable.

8 RPS and ESFAS are separate entities with respect to actuation logic. The RPS does not actuate the ESFAS. References to any interdependence between the two is deleted from the Bases for RTS Instrumentation.

9 Plant design basis does not include a semi-automatic testing device.

Testing is performed by removing each train from service, one at a time. Train logic is tested manually, using test switches provided in the reactor protection cabinets. When one train is out of service, the opposite train is relied upon to initiate a reactor trip upon receipt of a reactor trip signal.

10 The manual reactor trip, safety injection, steam line isolation, and containment spray actuating devices are push-buttons. Manual actuation of the reactor trip or safety injection requires depressing either of the installed push buttons for Safety Injection (SI) or RPS. Manual initiation of containment spray requires depressing both of the actuation buttons for this function simultaneously. This change reflects the actual plant hardware configuration.

11 Many parameters in the plant are monitored which have "Trip Setpoints" that are not ESFAS or RPS inputs. The term, "RPS or Engineered Safety Features Actuation System (ESFAS)," is added to clarify which approaching Trip Setpoints the reactor operator is likely to react to by initiating a manual reactor trip.

12 Bases presentation are modified to explain that manual reactor trip or applicable automatic reactor trip functions cannot be inoperable simply because the control rods are not capable of withdrawal. When the reactor trip breakers are closed and shutdown bank(s) are withdrawn, then these rods are credited as part of the shutdown margin. Because they are credited in the shutdown margin as being "trippable," it follows that those functions necessary for manual or automatic tripping of the reactor be operable, regardless of whether the rods are capable of being withdrawn. While the continuous rod withdrawal accident is one reactivity transient of concern during MODES 3, 4, and 5, the steam line break, rod ejection, and boron dilution accidents are also mitigated by the RPS when shutdown or control banks are withdrawn. As such, it is prudent to maintain the manual and applicable automatic trips (e.g., source range high flux trip) operable when the Rod Control System is capable of rod withdrawal or one or more rods are not fully inserted into the core.

13 The Nuclear Instrumentation System does not provide input to the steam generator water level control system. Therefore, this term is replaced with "Turbine Control System," since the power range instruments do provide input to the automatic runback circuitry for the turbine.

14 The Nuclear Instrumentation System does not provide a "High Positive Rate" or "High Negative Rate" trip signal to the RPS. Therefore, this section and all references to these functions are deleted from the Bases. Subsequent sections are renumbered accordingly.

15 During normal plant cooldown from MODE 3 to MODE 5 or heatup from MODE 5

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	----------NOTE---------- Not required to be performed for the logic inputs from Source Range Neutron Flux detector prior to entering MODE 3 from MODE 2 until 4 hours after entry into MODE 3. ---------- Perform ACTUATION LOGIC TEST.	31 days on a STAGGERED TEST BASIS
SR 3.3.1.6	----------NOTE---------- Not required to be performed until 24 hours after THERMAL POWER is ≥ 50% RTP. ---------- Calibrate excore channels to agree with incore detector measurements.	92 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 4 hours after entry into MODE 3. ---------- Perform COT.	92 days

(continued)

Table 3.3.1-1 (page 1 of 7)
Reactor Protection System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	NOMINAL TRIP SETPOINT (1)
1. Manual Reactor Trip	1,2	2	B	SR 3.3.1.14	NA	NA
	3[a], 4[a], 5[a]	2	C	SR 3.3.1.14	NA	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	≤ 110.93% RTP	108% RTP (2)
b. Low	1[b],2	4	E	SR 3.3.1.1 SR 3.3.1.8 SR 3.3.1.11	≤ 26.93% RTP	24% RTP
3. Intermediate Range Neutron Flux	1[b], 2[c]	2	F,G	SR 3.3.1.1 SR 3.3.1.8 SR 3.3.1.11	≤ 37.02% RTP	25% RTP
	2[d]	2	H	SR 3.3.1.1 SR 3.3.1.8 SR 3.3.1.11	≤ 37.02% RTP	25% RTP
4. Source Range Neutron Flux	2[d]	2	I,J	SR 3.3.1.1 SR 3.3.1.8 SR 3.3.1.11	≤ 1.28 E5 cps	1.0 E5 cps
	3[a], 4[a], 5[a]	2	J,K	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.11	≤ 1.28 E5 cps	1.0 E5 cps
	3[e], 4[e], 5[e]	1	L	SR 3.3.1.1 SR 3.3.1.11	N/A	N/A

(continued)

(1) A channel is OPERABLE with an actual Trip Setpoint value found outside its calibration tolerance band provided the Trip Setpoint value is conservative with respect to its associated Allowable Value and the channel is re-adjusted to within the established calibration tolerance band of the Nominal Trip Setpoint.
(2) The Nominal Trip Setpoint is as stated unless reduced as required by one or more of the following requirements: LCO 3.2.1 Required Action A.2.2; LCO 3.2.2 Required Action A.1.2.2; or LCO 3.7.1 Required Action B.2.
(a) With Rod Control System capable of rod withdrawal, or one or more rods not fully inserted.
(b) Below the P-10 (Power Range Neutron Flux) interlock.
(c) Above the P-6 (Intermediate Range Neutron Flux) interlock.
(d) Below the P-6 (Intermediate Range Neutron Flux) interlock.
(e) With the RTBs open. In this condition, source range Function does not provide reactor trip but does provide indication and alarm.

Table 3.3.1-1 (page 2 of 7)
Reactor Protection System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	NOMINAL TRIP SETPOINT (1)
5. Overtemperature ΔT	1,2	3	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 (Page 3.3-18)	Refer to Note 1 (Page 3.3-18) (3)
6. Overpower ΔT	1,2	3	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 2 (Page 3.3-19)	Refer to Note 2 (Page 3.3-19) (3)
7. Pressurizer Pressure						
a. Low	1(f)	3	M	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10	≥ 1832.02 psig	1844 psig
b. High	1,2	3	E	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10	≤ 2381.11 psig	2376 psig
8. Pressurizer Water Level – High	1(f)	3	M	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10	≤ 91.64%	91%

(continued)

(1) A channel is OPERABLE with an actual Trip Setpoint value found outside its calibration tolerance band provided the Trip Setpoint value is conservative with respect to its associated Allowable Value and the channel is re-adjusted to within the established calibration tolerance band of the Nominal Trip Setpoint.
(3) The Nominal Trip Setpoint is as stated unless reduced as required by LCO 3.2.1 Required Action A.2.3.
(f) Above the P-7 (Low Power Reactor Trips Block) interlock.

Table 3.3.1-1 (page 3 of 7)
Reactor Protection System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	NOMINAL TRIP SETPOINT (1)
9. Reactor Coolant Flow – Low						
a. Single Loop	1(g)	3 per loop	N	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10	≥ 93.47%	94.26%
b. Two Loops	1(h)	3 per loop	M	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10	≥ 93.47%	94.26%
10. Reactor Coolant Pump (RCP) Breaker Position						
a. Single Loop	1(g)	1 per RCP	O	SR 3.3.1.14	NA	NA
b. Two Loops	1(h)	1 per RCP	M	SR 3.3.1.14	NA	NA
11. Undervoltage RCPs	1(f)	1 per bus	M	SR 3.3.1.9 SR 3.3.1.10	≥ 2959 V	3120 V
12. Underfrequency RCPs	1(f)	1 per bus	M	SR 3.3.1.10 SR 3.3.1.14	≥ 57.84 Hz	58.2 Hz
13. Steam Generator (SG) Water Level – Low Low	1,2	3 per SG	E	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10	≥ 15.36%	16%

(continued)

(1) A channel is OPERABLE with an actual Trip Setpoint value found outside its calibration tolerance band provided the Trip Setpoint value is conservative with respect to its associated Allowable Value and the channel is re-adjusted to within the established calibration tolerance band of the Nominal Trip Setpoint.
(f) Above the P-7 (Low Power Reactor Trips Block) interlock.
(g) Above the P-8 (Power Range Neutron Flux) interlock.
(h) Above the P-7 (Low Power Reactor Trips Block) interlock and below the P-8 (Power Range Neutron Flux) interlock.

Table 3.3.1-1 (page 4 of 7)
Reactor Protection System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	NOMINAL TRIP SETPOINT (1)
14. SG Water Level – Low	1,2	2 per SG	E	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10	≥ 29.36%	30%
Coincident with Steam Flow/ Feedwater Flow Mismatch	1,2	2 per SG	E	SR 3.3.1.1 SR 3.3.1.7 SR 3.3.1.10	≤ 7.06 E5 lbm/hr	6.4 E5 lbm/hr
15. Turbine Trip						
a. Low Auto Stop Oil Pressure	1(f)	3	P	SR 3.3.1.10 SR 3.3.1.15	≥ 40.87 psig	45 psig
b. Turbine Stop Valve Closure	1(f)	2	P	SR 3.3.1.15	NA	NA
16. Safety Injection (SI) Input from Engineered Safety Feature Actuation System (ESFAS)	1,2	2 trains	Q	SR 3.3.1.14	NA	NA

(continued)

(1) A channel is OPERABLE with an actual Trip Setpoint value found outside its calibration tolerance band provided the Trip Setpoint value is conservative with respect to its associated Allowable Value and the channel is re-adjusted to within the established calibration tolerance band of the Nominal Trip Setpoint.
(f) Above the P-7 (Low Power Reactor Trips Block) interlock.

Table 3.3.1-1 (page 5 of 7)
Reactor Protection System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	NOMINAL TRIP SETPOINT (1)
17. Reactor Protection System Interlocks						
a. Intermediate Range Neutron Flux, P-6	2[d]	2	S	SR 3.3.1.11 SR 3.3.1.13	≥ 7.29 E-11 amp	1 E-10 amp
b. Low Power Reactor Trips Block, P-7	1	1 per train	T	SR 3.3.1.13 SR 3.3.1.14	NA	NA
c. Power Range Neutron Flux, P-8	1	4	T	SR 3.3.1.11 SR 3.3.1.13	≤ 42.94% RTP	40% RTP
d. Power Range Neutron Flux, P-10	1,2	4	S	SR 3.3.1.11 SR 3.3.1.13	≥ 7.06% RTP and ≤ 12.94% RTP	10% RTP
e. Turbine Impulse Pressure, P-7 input	1	2	T	SR 3.3.1.1 SR 3.3.1.10 SR 3.3.1.13	≤ 10.71% turbine power	10% turbine power
18. Reactor Trip Breakers[i]	1,2	2 trains	R,V	SR 3.3.1.4	NA	NA
	3[a], 4[a], 5[a]	2 trains	C,V	SR 3.3.1.4	NA	NA
19. Reactor Trip Breaker Undervoltage and Shunt Trip Mechanisms	1,2	1 each per RTB	U	SR 3.3.1.4	NA	NA
	3[a], 4[a], 5[a]	1 each per RTB	C	SR 3.3.1.4	NA	NA
20. Automatic Trip Logic	1[j],2	2 trains	Q,V	SR 3.3.1.5	NA	NA
	3[a], 4[a], 5[a]	2 trains	C,V	SR 3.3.1.5	NA	NA

(1) A channel is OPERABLE with an actual Trip Setpoint value found outside its calibration tolerance band provided the Trip Setpoint value is conservative with respect to its associated Allowable Value and the channel is re-adjusted to within the established calibration tolerance band of the Nominal Trip Setpoint.
(a) With Reactor Trip Breakers (RTBs) closed, and either rods not fully inserted, or Rod Control System capable of rod withdrawal.
(d) Below the P-6 (Intermediate Range Neutron Flux) interlock.
(i) Including any reactor trip bypass breakers that are racked in and closed for bypassing an RTB.
(j) Below the P-6 (Intermediate Range Neutron Flux) interlock for the logic inputs from Source Range Neutron Flux detector channels.

Table 3.3.1-1 (page 6 of 7)
Reactor Protection System Instrumentation

Note 1: Overtemperature ΔT

The Overtemperature ΔT Function Allowable Value shall not exceed the following Nominal Trip Setpoint by more than 2.96% of ΔT span.

$$\Delta T_{setpoint} \leq \Delta T_0 \left\{ K_1 - K_2 \frac{(1+\tau_1 S)}{(1+\tau_2 S)}(T - T') + K_3(P - P') - f(\Delta I) \right\}$$

Where: ΔT_0 is the indicated ΔT at RTP, °F.
s is the Laplace transform operator, sec^{-1}.
T is the measured RCS average temperature, °F.
T' is the reference T_{avg} at RTP, ≤ 575.4°F.

P is the measured pressurizer pressure, psig
P' is the nominal RCS operating pressure, ≤ 2235 psig

$K_1 \leq 1.1265$ $K_2 = 0.01228/°F$ $K_3 = 0.00089/psig$
$\tau_1 \geq 20.08$ sec $\tau_2 \leq 3.08$ sec

f(ΔI) =	$2.4(q_b - q_t) - 17$	when $q_t - q_b < -17\%$ RTP
	0% of RTP	when $-17\% \text{ RTP} \leq q_t - q_b \leq 12\%$ RTP
	$2.4(q_t - q_b) - 12$	when $q_t - q_b > 12\%$ RTP

Where q_t and q_b are percent RTP in the upper and lower halves of the core, respectively, and $q_t + q_b$ is the total THERMAL POWER in percent RTP.

Table 3.3.1-1 (page 7 of 7)
Reactor Protection System Instrumentation

Note 2: Overpower ΔT

The Overpower ΔT Function Allowable Value shall not exceed the following Nominal Trip Setpoint by more than 3.17% of ΔT span.

$$\Delta T_{setpoint} \leq \Delta T_0 \left\{ K_4 - K_5 \left(\frac{\tau_3 S}{1+\tau_3 S} \right) T - K_6 (T - T') - f(\Delta I) \right\}$$

Where: ΔT_0 is the indicated ΔT at RTP, °F.
s is the Laplace transform operator, sec^{-1}.
T is the measured RCS average temperature, °F.
T' is the reference T_{avg} at RTP, ≤ 575.4°F.

$K_4 \leq 1.06$

$K_5 \geq 0.02/°F$ for increasing T_{avg}
$0/°F$ for decreasing T_{avg}

$K_6 \geq 0.00277/°F$ when $T > T'$
$0/°F$ when $T \leq T'$

$\tau_3 \geq 9$ sec

f(ΔI) = as defined in Note 1 for Overtemperature ΔT

Table 3.3.2-1 (page 1 of 4)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	NOMINAL TRIP SETPOINT (1)
1. Safety Injection						
a. Manual Initiation	1,2,3,4	2	B	SR 3.3.2.6	NA	NA
b. Automatic Actuation Logic and Actuation Relays	1,2,3,4	2 trains	C	SR 3.3.2.2 SR 3.3.2.3 SR 3.3.2.5	NA	NA
c. Containment Pressure - High	1,2,3,4	3	E	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	≤ 4.45 psig	4 psig
d. Pressurizer Pressure - Low	1,2,3[a]	3	D	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	≥ 1709.89 psig	1715 psig
e. Steam Line High Differential Pressure Between Steam Header and Steam Lines	1,2,3[a]	3 per steam line	D	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	≤ 108.95 psig	100 psig
f. High Steam Flow in Two Steam Lines	1,2[b],3[b]	2 per steam line	D	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	(c)	(d)
Coincident with T_{avg} - Low	1,2[b],3[b]	1 per loop	D	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	≥ 541.50 °F	543°F
g. High Steam Flow in Two Steam Lines	1,2[b],3[b]	2 per steam line	D	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	(c)	(d)
Coincident with Steam Line Pressure - Low	1,2[b],3[b]	1 per loop	D	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	≥ 605.05 psig	614 psig

(continued)

(1) A channel is OPERABLE with an actual Trip Setpoint value found outside its calibration tolerance band provided the Trip Setpoint value is conservative with respect to its associated Allowable Value and the channel is re-adjusted to within the established calibration tolerance band of the Nominal Trip Setpoint.
(a) Above the Pressurizer Pressure interlock.
(b) Above the T_{avg}-Low interlock.
(c) Less than or equal to a function defined as ΔP corresponding to 41.58% full steam flow below 20% load, and ΔP increasing linearly from 41.58% full steam flow at 20% load to 110.5% full steam flow at 100% load, and ΔP corresponding to 110.5% full steam flow above 100% load.
(d) A function defined as ΔP corresponding to 37.25% full steam flow between 0% and 20% load and then a ΔP increasing linearly from 37.25% steam flow at 20% load to 109% full steam flow at 100% load.

Table 3.3.2-1 (page 2 of 4)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	NOMINAL TRIP SETPOINT (1)
2. Containment Spray						
a. Manual Initiation	1,2,3,4	2 trains	I	SR 3.3.2.6	NA	NA
b. Automatic Actuation Logic and Actuation Relays	1,2,3,4	2 trains	C	SR 3.3.2.2 SR 3.3.2.3 SR 3.3.2.5	NA	NA
c. Containment Pressure						
High High	1,2,3,4	6 (2 sets of 3)	E	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	≤ 20.45 psig	20 psig
3. Containment Isolation						
a. Phase A Isolation						
(1) Manual Initiation	1,2,3,4	2	B	SR 3.3.2.6	NA	NA
(2) Automatic Actuation Logic and Actuation Relays	1,2,3,4	2 trains	C	SR 3.3.2.2 SR 3.3.2.3 SR 3.3.2.5	NA	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 trains	I	SR 3.3.2.6	NA	NA
(2) Automatic Actuation Logic and Actuation Relays	1,2,3,4	2 trains	C	SR 3.3.2.2 SR 3.3.2.3 SR 3.3.2.5	NA	NA
(3) Containment Pressure						
High High	1,2,3,4	6 (2 sets of 3)	E	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	≤ 20.45 psig	20 psig

(continued)

(1) A channel is OPERABLE with an actual Trip Setpoint value found outside its calibration tolerance band provided the Trip Setpoint value is conservative with respect to its associated Allowable Value and the channel is re-adjusted to within the established calibration tolerance band of the Nominal Trip Setpoint.

Table 3.3.2-1 (page 3 of 4)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	NOMINAL TRIP SETPOINT (1)
4. Steam Line Isolation						
a. Manual Initiation	1,2(e),3(e)	1 per steam line	F	SR 3.3.2.6	NA	NA
b. Automatic Actuation Logic and Actuation Relays	1,2(e),3(e)	2 trains	G	SR 3.3.2.2 SR 3.3.2.3 SR 3.3.2.5	NA	NA
c. Containment Pressure – High High	1,2(e),3(e)	6 (2 sets of 3)	D	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	≤ 20.45 psig	20 psig
d. High Steam Flow in Two Steam Lines	1,2(e),3(e)	2 per steam line	D	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	(c)	(d)
Coincident with T_{avg} – Low	1,2(e), 3(e)(b)	1 per loop	D	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	≥ 541.50 °F	543°F
e. High Steam Flow in Two Steam Lines	1,2(e),3(e)	2 per steam line	D	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	(c)	(d)
Coincident with Steam Line Pressure – Low	1,2(e),3(e)	1 per steam line	D	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	≥ 605.05 psig	614 psig

(continued)

(1) A channel is OPERABLE with an actual Trip Setpoint value found outside its calibration tolerance band provided the Trip Setpoint value is conservative with respect to its associated Allowable Value and the channel is re-adjusted to within the established calibration tolerance band of the Nominal Trip Setpoint.
(b) Above the T_{avg}-Low interlock.
(c) Less than or equal to a function defined as ΔP corresponding to 41.58% full steam flow below 20% load, and ΔP increasing linearly from 41.58% full steam flow at 20% load to 110.5% full steam flow at 100% load, and ΔP corresponding to 110.5% full steam flow above 100% load.
(d) Less than or equal to a function defined as ΔP corresponding to 37.25% full steam flow between 0% and 20% load and then a ΔP increasing linearly from 37.25% steam flow at 20% load to 109% full steam flow at 100% load.
(e) Except when all MSIVs are closed.

Table 3.3.2-1 (page 4 of 4)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	NOMINAL TRIP SETPOINT (1)
5. Feedwater Isolation						
a. Automatic Actuation Logic and Actuation Relays	1,2[f],3[f]	2 trains	G	SR 3.3.2.2 SR 3.3.2.3 SR 3.3.2.5	NA	NA
b. Safety Injection	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.					
6. ESFAS Interlocks						
a. Pressurizer Pressure Low	1,2,3	3	H	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	≤ 2005.11 psig	2000 psig
b. T_{avg} – Low	1,2,3	1 per loop	H	SR 3.3.2.1 SR 3.3.2.4 SR 3.3.2.7	≤ 544.50 °F	543°F

(1) A channel is OPERABLE with an actual Trip Setpoint value found outside its calibration tolerance band provided the Trip Setpoint value is conservative with respect to its associated Allowable Value and the channel is re-adjusted to within the established calibration tolerance band of the Nominal Trip Setpoint.
(f) Except when all MFIVs, MFRVs, and bypass valves are closed or isolated by a closed manual valve.

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Degraded Voltage Function with one channel per bus inoperable.	B.1 Place channel in trip.	6 hours
C. Degraded Voltage Function with two or more channels per bus inoperable.	C.1 Restore all but one channel to OPERABLE status.	1 hour
D. Required Action and associated Completion Time not met.	D.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	----------NOTE---------- Verification of setpoint not required. ---------- Perform TADOT.	18 months

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.5.2	Perform CHANNEL CALIBRATION with Trip Setpoints as follows: a. Loss of voltage Trip Setpoint of 328 V ± 10% with a time delay of ≤ 1 second (at zero voltage). b. Degraded voltage Trip Setpoint of 430 V ± 4 V with a time delay of 10 ± 0.5 seconds.	18 months

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. (continued)	C.2.1 Be in MODE 3. AND C.2.2 Be in MODE 4.	12 hours 18 hours
D. One channel inoperable.	D.1 Restore channel to OPERABLE status. OR D.2.1 Be in MODE 3. AND D.2.2 Be in MODE 4.	48 hours 54 hours 60 hours
E. One Main Feedwater Pumps trip channel inoperable.	E.1 Restore channel to OPERABLE status. OR E.2 Be in MODE 3.	48 hours 54 hours

Table 3.3.8-1 (page 1 of 1)
Auxiliary Feedwater System Instrumentation

	FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	NOMINAL TRIP SETPOINT (1)
1.	SG Water Level–Low Low	1,2,3	3 per SG	C	SR 3.3.8.1 SR 3.3.8.2 SR 3.3.8.4	≥ 15.36%	16%
2.	Safety Injection	Refer to LCO 3.3.2, "ESFAS Instrumentation," Function 1, for all initiation functions and requirements.					
3.	Loss of Offsite Power	1,2,3	2 per bus	D	SR 3.3.8.3 SR 3.3.8.4	NA	328 V ± 10% with ≤ 1 sec time delay
4.	Undervoltage Reactor Coolant Pump	1,2,3	2 per bus	B	SR 3.3.8.3 SR 3.3.8.4	≥ 2959 V	3120 V
5.	Trip of all Main Feedwater Pumps	1,2	1 per pump	E	SR 3.3.8.3	NA	NA

(1) A channel is OPERABLE with an actual Trip Setpoint value found outside its calibration tolerance band provided the Trip Setpoint value is conservative with respect to its associated Allowable Value and the channel is re-adjusted to within the established calibration tolerance band of the Nominal Trip Setpoint.

BASES

BACKGROUND (continued)

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 illustrated in the UFSAR, 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. Signal Process Control and Protection System, including Analog Protection System, Nuclear Instrumentation System (NIS), field contacts, and protection channel sets: 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 relay logic: initiates proper unit shutdown and/or ESF actuation 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.

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. To account for the calibration tolerances and instrument drift, which are assumed to occur between calibrations, statistical allowances are provided in the Nominal Trip Setpoint and

(continued)

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BACKGROUND

Field Transmitters or Sensors (continued)

Allowable Values. The OPERABILITY of each transmitter or sensor can be evaluated when its "as found" calibration data are compared against its documented acceptance criteria.

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 by safety analyses. These setpoints are defined in UFSAR, Chapter 7 (Ref. 1), Chapter 6 (Ref. 2), and Chapter 15 (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 input bays. 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.

The instrumentation system is designed in accordance with HBRSEP design criteria, which is described in UFSAR Section 3.1 (Ref. 4), and IEEE-279-1968 (Ref. 5).

Where a plant condition that requires protective action can be brought on by a failure or malfunction of the control system, and the same failure or malfunction prevents proper action of a protection system channel or channels designed to protect against the resultant unsafe condition, the remaining portions of the protection system will automatically initiate appropriate protective action whenever a plant condition monitored by the system reaches its trip setpoint. No single failure within the protection system will prevent proper protection system action when required. These requirements are described in Reference 5.

(continued)

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BACKGROUND

Signal Process Control and Protection System (continued)

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 Nominal Trip Setpoints are the nominal values at which the bistables are set. Any bistable is considered to be properly adjusted (in accordance with the Nominal Trip Setpoint) when the "as left" value is within the established calibration tolerance band. A channel is required to be adjusted, if the actual Trip Setpoint is found outside the "as found" calibration tolerance band, such that the actual Trip Setpoint is within the "as left" calibration tolerance band.

The Nominal Trip Setpoints used in the bistables are based on the analytical limits stated in Reference 3. The selection of these Nominal Trip Setpoints is such that adequate protection is provided when all sensor and processing time delays accounted for in setpoint calculations and accident analyses are taken into account. To allow for calibration tolerances, instrumentation uncertainties, instrument drift, and severe environment errors for those RPS channels that must function in harsh environments as defined by 10 CFR 50.49 (Ref. 6), the Nominal Trip Setpoints and Allowable Values specified in Table 3.3.1-1 in the accompanying LCO are conservatively adjusted with respect to the analytical limits. A detailed description of the methodology used to calculate the Nominal Trip Setpoints, including their explicit uncertainties, is provided in the company setpoint methodology procedure (Ref. 8). The actual Nominal Trip Setpoint entered into the bistable is more conservative than that specified by the Allowable Value to account for changes in random measurement errors detectable by a COT. One example of such a change in measurement error is drift during the surveillance interval. As noted in Table 3.3.1-1 (Note I), a channel is considered OPERABLE with an actual Trip Setpoint value found outside its "as found" calibration tolerance band provided the TRIP Setpoint value is conservative with respect to its

(continued)

BASES

BACKGROUND

Trip Setpoints and Allowable Values (continued)

associated Allowable Value and the channel is re-adjusted to within the "as-left" calibration tolerance band of the Nominal Trip Setpoint. Notes allow the Nominal Trip Setpoints to be reduced when required by Required Actions.

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). Note that in the accompanying LCO 3.3.1, the Allowable Values are the LSSS.

Each channel of the analog 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 the company setpoint methodology procedure (Ref. 8). Once a designated channel is taken out of service for testing, a simulated signal is injected into the channel for testing. The process equipment for the channel in test is then tested, verified, and calibrated. SRs for the channels are specified in the SRs section.

The Nominal Trip Setpoints and Allowable Values listed in Table 3.3.1-1 are based on the methodology described in the company setpoint methodology procedure (Ref. 8), which incorporates all of the applicable uncertainties for each channel. The magnitudes of these uncertainties are factored into the determination of each Nominal Trip Setpoint. All field sensors and signal processing equipment for these channels are assumed to operate within the allowances of these uncertainty magnitudes.

Reactor Protection System Relay Logic

This equipment is used for the decision logic processing of outputs from the signal processing equipment bistables. To meet the redundancy requirements, two trains of RPS 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 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

(continued)

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BACKGROUND

Reactor Protection System Relay Logic (continued)

its own cabinets 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, generates the electrical output signal that will initiate the required trip, and provides the status, permissive, and annunciator output signals to the main control room of the unit.

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. Examples are given in the Applicable Safety Analyses, LCO, and Applicability sections of this Bases.

Reactor Trip Switchgear

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 RPS relay logic 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 RPS relay logic 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 RTB 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 RPS relay logic. Either the undervoltage coil or the

(continued)

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Reactor Trip Switchgear (continued)

shunt trip mechanism is sufficient by itself, thus providing a diverse trip mechanism.

The RPS relay logic matrix Functions are described in the functional diagrams included in Reference 1. In addition to the reactor trip or ESF, these diagrams also describe the various "permissive interlocks" that are associated with unit conditions. When an RPS train is removed from service for testing, the other train is relied upon to provide the automatic reactor protection requirements.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The RPS functions to maintain the SLs during all AOOs and mitigates the consequences of DBAs in all MODES in which the RTBs are closed.

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 for the unit. 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.

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 in each logic Function, and two trains in each Automatic Trip Logic Function. 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.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

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 the reactor operator to shut down the reactor whenever any RPS or Engineered Safety Features Actuation System (ESFAS) 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 since withdrawn rods are required to insert to satisfy SDM requirements in those MODES. With the Control Rod Drive (CRD) System capable of withdrawing the shutdown rods or the control rods in MODE 3, 4, or 5, inadvertent control rod withdrawal is possible. Therefore, manual reactor trip is also required in this condition. In MODE 3, 4, or 5, manual initiation of a reactor trip does not have to be OPERABLE if the RTBs are open. If the RTBs are open, there is no need to be able to trip the reactor because all of the rods are inserted. This requirement maintains maximum shutdown margin available in the event of a reactivity excursion while in MODES 3, 4, or 5. In MODE 6, neither the shutdown rods nor the control rods are permitted to be

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1. Manual Reactor Trip (continued)

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 the Turbine Control System. Therefore, the actuation logic must be able 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 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.

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

(continued)

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

a. Power Range Neutron Flux–High (continued)

are extremely unlikely. Other RPS Functions and administrative controls provide protection against reactivity additions when in MODE 3, 4, 5, or 6.

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.

(continued)

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

4. Source Range Neutron Flux (continued)

In MODE 3, 4, or 5 with the Rod Control System capable of rod withdrawal, or if one or more rods are not fully inserted, the Source Range Neutron Flux trip Function must also be OPERABLE. In this condition, the Source Range Neutron Flux trip must be OPERABLE to provide core protection against a rod withdrawal, boron dilution, or steam line break accident. If the RTBs are open, the source range detectors are not required to trip the reactor. However, their monitoring Function must be OPERABLE to monitor core neutron levels and provide indication of reactivity changes that may occur as a result of events like a boron dilution. The requirements for the NIS source range detectors in MODE 6 are addressed in LCO 3.9.2, "Nuclear Instrumentation."

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 pressurizer 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 Function monitors both variation in power and flow since a decrease in flow has the same effect on ΔT as a power increase. 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

(continued)

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

d. Power Range Neutron Flux, P-10 (continued)

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.

e. Turbine Impulse Pressure

The Turbine Impulse Pressure sends a signal to P-7 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 to be OPERABLE in MODE 1.

The Turbine Impulse Pressure channels must be OPERABLE when the turbine generator is operating. The Function is not required OPERABLE in MODE 2, 3, 4, 5, or 6 because the turbine generator is not electrically loaded.

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 a trip breaker and bypass breaker associated with a single RPS logic train that are racked in, closed, and capable of supplying power to the CRD System. Thus, the train may consist of the main breaker with the associated bypass breaker racked out (or removed from the cubicle), or the main breaker and bypass breaker, from a single train (when one train is out of service in accordance with LCO 3.3.1 ACTIONS). Two OPERABLE trains ensure no single random failure can disable the RPS trip capability.

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

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

18. Reactor Trip Breakers (continued)

CRD System is capable of rod withdrawal, or 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 CRD 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 CRD System is capable of rod withdrawal, or 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 an undervoltage coil and a shunt trip coil to trip the breaker open when needed. Each RTB is equipped with a bypass breaker to allow testing of the trip breaker while the unit is at power. 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. The source range channel logic inputs are not required to be OPERABLE

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

20. Automatic Trip Logic (continued)

above the P-6 interlock. In MODE 3, 4, or 5, these RPS trip Functions must be OPERABLE when the CRD System is capable of rod withdrawal, or one or more rods are not fully inserted.

The RPS instrumentation satisfies Criterion 3 of the NRC Policy Statement.

ACTIONS

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 3.3.1-1.

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 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.

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BASES

ACTIONS

Q.1 and Q.2 (continued)

The Required Actions have been modified by a Note that allows bypassing one train up to 12 hours for maintenance or surveillance testing, provided the other train is OPERABLE.

R.1 and R.2

Condition R 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 removes the requirement for this particular Function.

The Required Actions have been modified by a Note which allows one channel to be bypassed for up to 12 hours for maintenance or surveillance testing, provided the other channel is OPERABLE.

S.1 and S.2

Condition S applies to the P-6 and P-10 interlocks. With one channel 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 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

(continued)

BASES

ACTIONS

S.1 and S.2 (continued)

LCO 3.0.3 for shutdown actions in the event of a complete loss of RPS Function.

T.1 and T.2

Condition T applies to the P-7, P-8, and Turbine Impulse Pressure inputs. With one channel 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.

U.1, U.2.1, and U.2.2

Condition U 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) followed by opening the RTBs in 1 additional hour (55 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. With the RTBs open and the unit in MODE 3, this trip Function is no longer required to be OPERABLE. The affected RTB should not be bypassed while one of the diverse features is inoperable except for the time required to perform maintenance to one of the diverse features. The allowable time for performing maintenance or surveillance

(continued)

BASES

ACTIONS

U.1, U.2.1, and U.2.2 (continued)

testing the diverse features is 12 hours for the reasons stated under Condition R.

The Completion Time of 48 hours for Required Action U.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.

V.1

With two RPS trains inoperable, no automatic capability is available to shut down the reactor, and immediate plant shutdown in accordance with LCO 3.0.3 is required.

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 trains of the RPS. When testing Channel I, Train A and Train B must be examined. Similarly, Train A and Train B must be examined when testing Channel II, Channel III, and Channel IV (if applicable). 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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.1 (continued)

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.

Deviation 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 3.3.1.2

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 12 hours are 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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.2 (continued)

reliability and operating history data for instrument drift. Together these 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 and overpower ΔT Functions.

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 ≥ 15% RTP and that 36 hours is allowed for performing the first Surveillance after reaching 15% RTP.

The Frequency of every 31 EFPD is adequate. It is based on industry 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.

The RTB test shall include separate verification of the undervoltage and shunt trip mechanisms. Independent

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.4 (continued)

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 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 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. 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.

A note is added to SR 3.3.1.5 stating that the SR is not required to be performed for the source range neutron flux detector channels prior to entry into MODE 3 from MODE 2 until 4 hours after entry into MODE 3. This Note allows normal shutdown to proceed without delay for testing in MODE 2 and in MODE 3 until the RTBs are open and SR 3.3.1.5 is no longer required to be performed (i.e., the 4 hour delay allows a normal shutdown to be completed without a required hold on power reduction to perform the testing required by this SR). If the unit is in MODE 3 with the RTBs closed for greater than 4 hours, this SR must be performed prior to 4 hours after entry into MODE 3.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

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(ΔI) input to the overtemperature and overpower ΔT Functions.

A Note modifies SR 3.3.1.6. The Note states that this Surveillance is required only if reactor power is > 50% RTP and that 24 hours is allowed for performing the first surveillance after reaching 50% RTP.

The Frequency of 92 EFPD is adequate. It is based on industry 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 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 (Ref. 8). The setpoint shall be left set consistent with the assumptions of the current unit specific setpoint methodology (Ref. 8).

The "as found" and "as left" values must also be recorded and reviewed for consistency with the assumptions of Reference 7.

SR 3.3.1.7 is modified by a Note that provides a 4 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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.7 (continued)

a delay for testing in MODE 2 and for a short time in MODE 3 until the RTBs are open and SR 3.3.1.7 is no longer required to be performed (i.e., the 4 hour delay allows a normal shutdown to be completed without a required hold on power reduction to perform the testing required by this SR). In addition, performing the COT of the source range instrumentation prior to entry into MODE 3 from MODE 2 may increase the probability of a reactor trip. If the unit is to be in MODE 3 with the RTBs closed for > 4 hours this Surveillance must be performed prior to 4 hours after entry into MODE 3.

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 four hours after reducing power below P-10 and 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 "4 hours after reducing power below P-10" (applicable to intermediate and power range low channels) and "4 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 and four hours after reducing power below P-10 or P-6. 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 4 hours, then the

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.8 (continued)

testing required by this surveillance must be performed prior to the expiration of the 4 hour limit. Four hours is a reasonable time to complete the required testing or place the unit in a MODE where this surveillance is no longer required. This test ensures that the NIS source, intermediate, and power range low channels are OPERABLE prior to taking the reactor critical and after reducing power into the applicable MODE (< P-10 or < P-6) for periods > 4 hours.

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 every 18 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.

CHANNEL CALIBRATIONS must be performed consistent with the assumptions of the unit specific setpoint methodology (Ref. 8). 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 (Ref. 8).

The Frequency of 18 months is based on the assumption of an 18 month calibration interval in the determination of the magnitude of equipment drift in the setpoint methodology (Ref. 8).

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.10 (continued)

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. This Note applies to those Functions equipped with electronic dynamic compensation. Not all Functions to which SR 3.3.1.10 is applicable are equipped with electronic dynamic compensation.

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 18 months. This SR is modified by a Note stating that neutron detectors are excluded from the CHANNEL CALIBRATION. 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 18 month Frequency is based on industry operating experience, considering instrument reliability and operating history data. Operating experience has shown these components usually pass the Surveillance when performed on the 18 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 18 months. For Table 3.3.1-1 Functions 5 and 6, the CHANNEL CALIBRATION shall include a narrow range RTD cross calibration. This SR is modified by a Note stating that this test shall include verification of the electronic dynamic compensation time constants and the RTD response time constants. The RCS

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.12 (continued)

narrow range temperature sensors response time shall be ≤ a 4.0 second lag time constant.

The Frequency is justified by the assumption of an 18 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 18 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 and the P-7 interlock. This TADOT is performed every 18 months. The test shall independently verify the OPERABILITY of the undervoltage and shunt trip mechanisms for the Manual Reactor Trip Function for the Reactor Trip Breakers and the undervoltage trip mechanism for the Reactor Trip Bypass Breakers.

The test shall also independently verify the OPERABILITY of the low power reactor trip block from the Power Range Neutron Flux (P-10) interlock and turbine first stage pressure. The TADOT verifies that when either the Turbine Impulse Pressure inputs or the Power Range Neutron Flux (P-10) interlock engage, reactor trips that are blocked by P-7 are enabled.

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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BASES

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 of a TADOT of Turbine Trip Functions. This TADOT is as described in SR 3.3.1.4, except that this test is performed prior to reactor startup. A Note states that this Surveillance is not required if it has been performed within the previous 31 days. Verification of the Trip Setpoint does not have to be performed for this Surveillance. 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 and must therefore be performed prior to reactor startup.

REFERENCES

1. UFSAR, Chapter 7.
2. UFSAR, Chapter 6.
3. UFSAR, Chapter 15.
4. UFSAR, Section 3.1.
5. IEEE-279-1968.
6. 10 CFR 50.49.
7. WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990.
8. Attachment VII to CP&L's letter to NRC dated May 30, 1997, H. B. Robinson Steam Electric Plant, Unit No. 2, "Response to Request for Additional Information Regarding the Technical Specifications Change Request to Convert to the Improved Standard Technical Specifications.

BASES

BACKGROUND

Field Transmitters or Sensors (continued)

the Nominal Trip Setpoint and Allowable Values. The OPERABILITY of each transmitter or sensor can be evaluated when its "as found" 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 UFSAR, Chapter 6 (Ref. 1), Chapter 7 (Ref. 2), and Chapter 15 (Ref. 3). If the measured value of a unit parameter exceeds the predetermined setpoint, an output from a bistable is forwarded to the ESFAS automatic initiation logic. Channel separation is maintained up to and through the input to the ESFAS automatic initiation logic.

The ESFAS automatic initiation instrumentation is designed in accordance with HBRSEP design criteria, which is described in UFSAR Section 3.1 (Ref. 4), and IEEE-279-1968 (Ref. 5).

Where a plant condition that requires protective action can be brought on by a failure or malfunction of the control system, and the same failure or malfunction prevents proper action of a protection system channel or channels designed to protect against the resultant unsafe condition, the remaining portions of the protection system will automatically initiate appropriate protective action whenever a plant condition monitored by the system reaches its trip setpoint. No single failure within the protection system will prevent proper protection system action when required. These requirements are described in Reference 5.

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BASES

BACKGROUND (continued)

Trip Setpoints and Allowable Values

The Nominal Trip Setpoints are the nominal values at which the bistables are set. Any bistable is considered to be properly adjusted (in accordance with the Nominal Trip Setpoint) when the "as left" value is within the established calibration tolerance band. A channel is required to be adjusted, if the actual Trip Setpoint is found outside the "as found" calibration tolerance band, such that the actual Trip Setpoint is within the "as left" calibration tolerance band.

The Nominal Trip Setpoints used in the bistables are based on the analytical limits stated in Reference 2. The selection of these Nominal Trip Setpoints is such that adequate protection is provided when all sensor and processing time delays accounted for in setpoint calculations and accident analyses are taken into account. To allow for calibration tolerances, instrumentation uncertainties, instrument drift, and severe environment errors for those ESFAS channels that must function in harsh environments as defined by 10 CFR 50.49 (Ref. 6), the Nominal Trip Setpoints and Allowable Values specified in Table 3.3.2-1 in the accompanying LCO are conservatively adjusted with respect to the analytical limits. A detailed description of the methodology used to calculate the Nominal Trip Setpoints, including their explicit uncertainties, is provided in the company setpoint methodology procedure (Ref. 9). The actual Nominal Trip Setpoint entered into the bistable is more conservative than that specified by the Allowable Value to account for changes in random measurement errors detectable by a COT. One example of such a change in measurement error is drift during the surveillance interval. As noted in Table 3.3.2-1 (Note 1), a channel is considered OPERABLE with an actual Trip Setpoint value found outside its "as found" calibration tolerance band provided the Trip Setpoint value is conservative with respect to its Allowable Value and the Channel is re-adjusted to within the "as left" calibration tolerance band of the Nominal Trip Setpoint.

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.

(continued)

BASES

BACKGROUND

Trip Setpoints and Allowable Values (continued)

Each channel can be tested on line to verify that the signal processing equipment and setpoint accuracy is within the specified allowance requirements of calculations performed in accordance with the company setpoint methodology procedure (Ref. 9). 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

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BASES

BACKGROUND

Trip Setpoints and Allowable Values (continued)

calibrated. SRs for the channels are specified in the SR section.

The Nominal Trip setpoints and Allowable Values listed in Table 3.3.2-1, are based on the methodology described in the company setpoint methodology procedure (Ref. 9), which incorporates all of the applicable uncertainties for each channel. The magnitudes of these uncertainties are factored into the determination of each Nominal Trip Setpoint. All field sensors and signal processing equipment for these channels are assumed to operate within the allowances of these uncertainty magnitudes.

ESFAS Automatic Initiation Logic

The ESFAS 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 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 cabinets for physical and electrical separation to satisfy separation and independence requirements.

The ESFAS 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 of the unit.

The bistable outputs from the signal processing equipment are sensed by the relay logic and combined into logic matrices that represent combinations indicative of various transients. If a required logic matrix 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.

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1. Safety Injection (continued)

- Start of AFW to ensure secondary side cooling capability; and
- Activation of the control room filtration system to ensure habitability.

a. Safety Injection – Manual Initiation

The LCO requires one channel per train to be OPERABLE. The operator can initiate SI at any time by using either of two pushbuttons 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. Safety Injection – Automatic Actuation Logic and Actuation Relays

This LCO requires two trains to be OPERABLE. Actuation logic consists of all circuitry housed 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, 3, and 4 as indicated in Table 3.3.2-1. In these MODES, there is sufficient energy in the primary and secondary systems to warrant automatic initiation of ESF systems. Because of the large number of components actuated on a SI, actuation is simplified by the use of the manual actuation

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

b. Safety Injection-Automatic Actuation Logic and Acutation Relays (continued)

push buttons. In addition, the Containment Pressure - High Function is required to be OPERABLE in MODE 4 since there may be sufficient energy in the primary or secondary systems to pressurize the containment following a pipe break. Therefore, automatic actuation logic and actuation relays must be OPERABLE in MODE 4 to support OPERABILITY of the Manual Initiation and Containment Pressure - High Functions.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

d. Safety Injection – Pressurizer Pressure – Low (continued)

performed by the Containment Pressure – High signal.

This Function is not required to be OPERABLE in MODE 3 below the 2000 psig 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. Steam Line – High Differential Pressure Between Steam Header and Steam Lines

Steam Line – High Differential Pressure provides protection against the following accidents:

- SLB upstream of MSL check valves;
- Feed line break; and
- Inadvertent opening of an SG relief or an SG safety valve.

With the transmitters located away from the main steam headers, it is not possible for them to experience adverse environmental conditions during an SLB event. Therefore, the Trip Setpoint from which the Allowable Value is calculated reflects only steady state instrument uncertainties. Steam line high differential pressure must be OPERABLE in MODES 1, 2, and 3 for RCS pressure ≥ 2000 psig 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 3 with RCS pressure < 2000 psig, 4, 5, or 6 because there is not sufficient energy in the secondary side of the unit to cause an accident.

(continued)

BASES

ACTIONS

B.1, B.2.1 and B.2.2 (continued)

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. 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 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; and
- Containment Spray.

This action addresses the train orientation of the relay logic and the master and slave relays. Due to the plant design, maintenance of a single channel can not be performed without causing all channels of the associated Function to be inoperable. In many cases, maintenance will also cause the associated train to be inoperable.

For repair or replacement of Engineered Safeguard System relays and/or test switches, 12 hours is a reasonable Completion Time for restoration of the two most frequently occurring types of failures that occur in the HBRSEP Unit No. 2 Engineered Safeguards System. These two failures are 1) failure of a logic or actuation relay, and 2) failure of the test switches used for the performance of the surveillance testing. A failure of either of these items

(continued)

BASES

ACTIONS

C.1, C.2.1 and C.2.2 (continued)

only causes one portion of the Engineered Safeguards System to be inoperable, but due to the wiring configuration of the system (the common side of the relay power source is "daisy chained" together) the entire train must be considered inoperable once maintenance on the failed item has commenced.

The allowed time of 12 hours for inoperability of a single train on an ESFAS instrumentation train is considered to be acceptable based on the fact that the other ESFAS instrumentation train is available to perform the actuation function and the low probability of an event requiring an ESFAS actuation. In addition, the change provides the potential benefit of the avoidance of a plant shutdown transient by providing a time period to perform required surveillance testing or necessary maintenance prior to requiring a plant shutdown. If one train is inoperable, 12 hours are allowed to restore the train to OPERABLE status. The 12 hour Completion Time provides adequate time to perform maintenance or repairs to the automatic actuation logic and actuation relays. 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 (18 hours total time) and in MODE 5 within an additional 30 hours (48 hours total time). The Completion Times are reasonable, based on operating experience, to reach the required unit conditions

(continued)

BASES

ACTIONS

C.1, C.2.1, and C.2.2 (continued)

from full power conditions in an orderly manner and without challenging unit systems.

D.1, D.2.1, and D.2.2

Condition D applies to:

- Pressurizer Pressure – Low;
- Steam Line Differential Pressure – High;
- High Steam Flow in Two Steam Lines Coincident With T_{avg} – Low or Coincident With Steam Line Pressure – Low; and
- Steam Line Isolation Containment Pressure - High High.

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.

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.

(continued)

BASES

ACTIONS (continued)

E.1, E.2.1, and E.2.2

Condition E applies to:

- Safety Injection Containment Pressure – High; and
- Containment Spray Containment Pressure – High High.

(continued)

BASES

ACTIONS

F.1, F.2.1, and F.2.2 (continued)

occurring during this interval. If the Function 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.

The action addresses the train orientation of the relay logic and the master and slave relays for these functions. Due to the plant design, maintenance of a single channel can not be performed without causing all channels of the associated Function to be inoperable. In many cases, maintenance will also cause the associated train to be inoperable.

For repair or replacement of Engineered Safeguard System relays and/or test switches, 12 hours is a reasonable Completion Time for restoration of the two most frequently occurring types of failures that occur in the HBRSEP Unit No. 2 Engineered Safeguards System. These two failures are 1) failure of a logic or actuation relay, and 2) failure of the test switches used for the performance of the surveillance testing. A failure of either of these items only causes one portion of the Engineered Safeguards System to be inoperable, but due to the wiring configuration of the system (the common side of the relay power source is "daisy chained" together) the entire train must be considered inoperable once maintenance on the failed item has commenced.

The allowed time of 12 hours for inoperability of a single train on an ESFAS instrumentation train is considered to be acceptable based on the fact that the other ESFAS instrumentation train is available to perform the actuation

(continued)

BASES

ACTIONS

G.1, G.2.1 and G.2.2 (continued)

function and the low probability of an event requiring an ESFAS actuation. In addition, the change provides the potential benefit of the avoidance of a plant shutdown transient by providing a time period to perform required surveillance testing or necessary maintenance prior to requiring a plant shutdown. If one train is inoperable, 12 hours are allowed to restore the train to OPERABLE status. The 12 hour Completion Time provides adequate time to perform maintenance or repairs to the automatic actuation logic and actuation relays. 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. 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.

H.1, H.2.1 and H.2.2

Condition H applies to the Pressurizer Pressure-Low and T_{avg}-Low interlocks.

With one channel inoperable, the operator must verify that the interlock is in the required state for the existing unit

(continued)

BASES

ACTIONS

H.1, H.2.1 and H.2.2 (continued)

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 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 these interlocks.

I.1, I.2.1, I.2.2, and I.2.3

Condition I applies to the manual initiation function of Containment Spray and Phase B Isolation.

This action addresses the train orientation of the relay logic for the function. With one or more of the Containment Spray Manual Initiation pushbuttons inoperable, there is no means available to manually initiate Containment Spray or Phase B Containment Isolation through the automatic actuation relays. The Manual Initiation is set up on two-out-of-two logic, with only two pushbuttons provided, and a single failure of either of the pushbuttons renders the entire Manual Initiation function inoperable. Therefore, if a channel or train is inoperable, it must be returned to OPERABLE status within 1 hour. The 1 hour Completion Time is equal to the time allowed by LCO 3.0.3 to initiate shutdown actions in the event of a complete loss of ESFAS function. If the channel is not returned to OPERABLE status within the 1 hour Completion Time, the unit must be placed in MODE 3 within the next 6 hours, in MODE 4 within the following 6 hours, and in MODE 5 within the following 24 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

(continued)

BASES

ACTIONS

I.1, I.2.1, I.2.2 and I.2.3 (continued)

MODE 5 removes all requirements for OPERABILITY of this function.

SURVEILLANCE REQUIREMENTS

The SRs for each ESFAS Function are identified by the column of Table 3.3.2-1.

A Note (Note 1) 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 channel I, train A and train B must be examined. Similarly, train A and train B must be examined when testing channel II, channel III, and channel IV (if applicable). The CHANNEL CALIBRATION and COTs are performed in a manner that is consistent with the assumptions used in analytically calculating the required channel accuracies.

The Surveillances are also modified by Note 2 to indicate that when a channel is placed in an inoperable status solely for the performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the redundant ESFAS train is OPERABLE. Upon completion of the Surveillance or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and the Required Actions performed. If maintenance is to be subsequently performed as a result of a failed surveillance test, LCO 3.3.2 ACTIONS are applicable. Note 2 to the Surveillance Requirements is based on operating history which has shown that 6 hours is generally the time required to perform the channel surveillance with additional time to allow for short term plant changes or verification of any abnormal responses. This 6 hour testing allowance does not significantly reduce the probability that the ESFAS will initiate when necessary.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

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. The master relay is actuated by either a manual or automatic initiation of the function being tested. Contact operation is verified either by a continuity check of the circuit containing the master relay or proper operation of the end device during the supported equipment simulated or actual automatic actuation test. This test is performed every 18 months. The 18 month Frequency is adequate, based on industry operating experience, and is consistent with the typical refueling cycle, which provides the plant conditions necessary for testing.

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 Allowable Values specified in Table 3.3.2-1.

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 (Ref. 9). The setpoint shall be left set consistent with the assumptions of the current unit specific setpoint methodology (Ref. 9).

The "as found" and "as left" values must also be recorded and reviewed for consistency with the assumptions of the surveillance interval extension analysis in WCAP-10271-P-A (Ref. 8) when applicable.

The Frequency of 92 days is justified in Reference 8.

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 either by a continuity check

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.2.5 (continued)

of the circuit containing the slave relay, or by verification of proper operation of the end device during supported equipment simulated or actual automatic actuation test. This test is performed every 18 months. The 18 month Frequency is adequate, based on industry operating experience, and is consistent with the typical refueling cycle, which provides the plant conditions necessary for testing.

SR 3.3.2.6

SR 3.3.2.6 is the performance of a TADOT. This test is a check of Manual Actuation Functions. It is performed every 18 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 18 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. 9). 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.2.7 (continued)

The Frequency of 18 months is based on the assumption of an 18 month calibration interval in the determination of the magnitude of equipment drift in the setpoint methodology.

REFERENCES

1. UFSAR, Chapter 6.
2. UFSAR, Chapter 7.
3. UFSAR, Chapter 15.
4. UFSAR, Section 3.1.
5. IEEE-279-1968.
6. 10 CFR 50.49.
7. UFSAR, Section 6.2.4.
8. WCAP-10271-P-A, Supplement 2, Rev. 1, June 1990.
9. Attachment VIII to CPL's letter to NRC dated May 30, 1997, H. B. Robinson Steam Electric Plant, Unit No. 2 - Response to Request for Additional Information and Transmittal of Supplement 4 Regarding the Technical Specification Change Request to Convert to the Improved Standard Technical Specification.

BASES

BACKGROUND

Trip Setpoints and Allowable Values (continued)

These uncertainties are defined in the company setpoint methodology procedure (Ref. 4).

The dropout time delay on the loss of voltage relays is very short, almost instantaneous. This short time delay is necessary to preclude damage to equipment from operating on less than minimum manufacturer's recommended voltage for continuous motor operation. The dropout time delay on the degraded voltage relays is significantly longer. A long time delay is desired such that it will minimize the effects of short duration disturbances on the grid. However, the allowable time duration of a degraded voltage condition must be short enough that it will not result in failure of safety systems or components.

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 concurrent with 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 analyses assume a non-mechanistic DG loading, which does not explicitly account for each individual component of loss of power detection and subsequent actions.

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 UFSAR, Chapter 15 (Ref. 3), in which a loss of offsite power is assumed.

The delay times assumed in the safety analysis for the ESF equipment include the 10 second DG start delay, and the appropriate sequencing delay, if applicable. The response times for ESFAS actuated equipment in LCO 3.3.2, "Engineered Safety Feature Actuation System (ESFAS) Instrumentation,"

(continued)

BASES

ACTIONS

B.1 (continued)

The specified Completion Time and time allowed for tripping one channel are reasonable considering the Function remains fully OPERABLE on every bus and the low probability of an event occurring during these intervals.

C.1

Condition C applies when more than one degraded voltage channel on a single bus is inoperable.

Required Action C.1 requires restoring all but one channel on each bus to OPERABLE status. The 1 hour Completion Time should allow ample time to repair most failures and takes into account the low probability of an event requiring an LOP start occurring during this interval.

D.1

Condition D applies to each of the LOP DG start Functions when the Required Action and associated Completion Time for Condition A, B, or C are not met.

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.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.3.5.1

SR 3.3.5.1 is the performance of a TADOT. This test is performed every 18 months. 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.

The SR is modified by a Note that excludes verification of the setpoint from the TADOT. Setpoint verification is accomplished during the CHANNEL CALIBRATION.

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, should include a single point verification that the trip occurs within the required time delay, as shown in Reference 1.

A CHANNEL CALIBRATION is performed every 18 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 of 18 months is based on operating experience and consistency with the typical industry refueling cycle and is justified by the assumption of an 18 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

REFERENCES

1. UFSAR, Section 8.3.

2. CP&L Letter to NRC, Serial No. GD-79-2502, dated October 5, 1979, transmitting summary of "Degraded Grid Voltage Study for H.B. Robinson Unit No. 2," Ebasco Services, Incorporated, October 15, 1976

3. UFSAR, Chapter 15.

(continued)

BASES

REFERENCES (continued)

4. Attachment VIII to CPL's letter to NRC dated May 30, 1997, H. B. Robinson Steam Electric Plant, Unit No. 2 - Response to Request for Additional Information and Transmittal of Supplement 4 Regarding the Technical Specification Change Request to Convert to the Improved Standard Technical Specification.

BASES (continued)

APPLICABLE SAFETY ANALYSES

The containment ventilation isolation radiation monitors ensure closing of the ventilation isolation valves. They are the primary means for automatically isolating containment in the event of a fuel handling accident during shutdown. Containment isolation in turn ensures meeting the containment leakage rate assumptions of the safety analyses, and ensures that the calculated accidental offsite radiological doses are below 10 CFR 100 (Ref. 1) limits.

The containment ventilation isolation instrumentation satisfies Criterion 3 of the NRC Policy Statement.

LCO

The LCO requirements ensure that the instrumentation necessary to initiate Containment Ventilation Isolation, listed in Table 3.3.6-1, is OPERABLE.

1. Manual Initiation

The LCO requires two channels OPERABLE. The operator can initiate containment ventilation isolation at any time by using either of two pushbuttons in the control room. Either pushbutton actuates both trains. This action will cause actuation of Phase A and Containment Ventilation Isolation automatic containment isolation valves. Containment Ventilation Isolation can also be initiated by the manual Containment Spray buttons.

The LCO for Manual Initiation ensures the proper amount of redundancy is maintained in the manual actuation circuitry to ensure the operator has manual initiation capability.

Each channel consists of one push button and the interconnecting wiring to the actuation logic cabinet.

2. Automatic Actuation Logic and Actuation Relays

The LCO requires two trains of Automatic Actuation Logic and Actuation Relays to be OPERABLE. The Automatic Actuation Logic and Actuation Relays actuate containment ventilation isolation upon receipt of an actuation signal from the Containment Radiation or

(continued)

B 3.3 INSTRUMENTATION

B 3.3.8 Auxiliary Feedwater (AFW) System Instrumentation

BASES

BACKGROUND

The AFW System automatically supplies feedwater to the steam generators (SGs) to remove decay heat from the Reactor Coolant System (RCS) upon loss of normal feedwater supply. The AFW System can provide feedwater to the SGs from any one or combination of three AFW pumps, two of which are motor driven and the third of which is steam turbine driven.

The two motor driven AFW pumps are powered from emergency busses E-1 and E-2. These busses also supply power to the motor driven AFW pump discharge isolation valves and the turbine driven AFW pump steam supply and feedwater discharge isolation valves. The turbine driven AFW pump provides a second independent and diverse means of providing auxiliary feedwater to the SGs.

Initiation of an automatic actuation signal to the turbine driven AFW pump causes the turbine steam supply valves and the pump feedwater discharge isolation valves to open. An automatic actuation signal to the motor driven AFW pumps cause the pumps to become energized and accelerate up to speed, and the feedwater discharge isolation valves to open.

Two trains of AFW actuation relay logic are used to develop the coincident signals from the process inputs. Logic train A starts one motor driven AFW pump and Logic train B starts the second motor driven AFW pump. Each logic train independently actuates the turbine driven AFW pump.

The AFW automatic actuation instrumentation is discussed in UFSAR Section 7.3.1 (Ref. 1). The instrumentation is designed in accordance with HBRSEP design criteria, which is described in UFSAR Section 3.1 (Ref. 2).

Trip Setpoints and Allowable Values

The Nominal Trip Setpoints are the nominal values at which the bistables are set. Any bistable is considered to be properly adjusted (in accordance with the Nominal Trip Setpoint when the "as left" value is within the established calibration tolerance band. A channel is required to be adjusted, if the actual Trip Setpoint is found outside the

(continued)

BASES

BACKGROUND

Trip Setpoints and Allowable Values (continued)

"as found" calibration tolerance band, such that the actual Trip Setpoint is within the "as left" calibration tolerance band.

The Nominal Trip Setpoints used in the bistables are based on the analytical limits or design limits. The selection of these Nominal Trip Setpoints is such that adequate protection is provided when all sensor and processing time delays accounted for in setpoint calculations and accident analyses are taken into account. To allow for calibration tolerances, instrumentation uncertainties, instrument drift, and severe environment errors for those channels that must function in harsh environments as defined by 10 CFR 50.49, the Nominal Trip Setpoints and Allowable Values specified in Table 3.3.8-1 in the accompanying LCO are conservatively adjusted with respect to the analytical limits. A detailed description of the methodology used to calculate the Nominal Trip Setpoints, including their explicit uncertainties, is provided in the company setpoint methodology procedure (Ref. 9). The actual Nominal Trip Setpoint entered into the bistable is more conservative than that specified by the Allowable Value to account for changes in random measurement errors detectable by a COT. One example of such a change in measurement error is drift during the surveillance interval. As noted in Table 3.3.8-1 (Note 1), a channel is considered OPERABLE with an actual Trip Setpoint value found outside its "as found" calibration tolerance band provided the Trip Setpoint value is conservative with respect to its Allowable Value and the channel is re-adjusted to within the "as left" calibration tolerance band of the Nominal Trip Setpoint.

Setpoints in accordance with the Allowable Value ensure that the consequences of Design Basis Accidents (DBAs) and transients will be acceptable, providing the unit is operated from within the LCOs at the onset of the DBA or transient and the equipment functions as designed.

Each channel can be tested on line to verify that the signal processing equipment and setpoint accuracy is within the specified allowance requirements of calculations performed in accordance with the company setpoint methodology procedure (Ref. 9). Once a designated channel is taken out

(continued)

BASES

BACKGROUND

Trip Setpoints and Allowable Values (continued)

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 Nominal Trip Setpoints and Allowable Values listed in Table 3.3.8-1, are based on the methodoogy described in the company setpoint methodology procedure (Ref. 9), which incorporates all of the applicable uncertainties for each channel. The magnitudes of these uncertainties are factored into the determination of each Nominal Trip Setpoint. All field sensors and signal processing equipment for these channels are assumed to operate within the allowances of these uncertainty magnitudes.

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 SGs to remove decay heat and other residual heat by delivering at least the minimum required flow rate to the SGs at pressures corresponding to the lowest main steam safety valve (MSSV) set pressure plus 3%.

In addition, the AFW System must supply enough makeup water to replace SG secondary inventory lost as the unit cools to MODE 4 conditions. Sufficient AFW flow must also be available to account for flow losses such as pump recirculation and line breaks.

The limiting Design Basis Accidents (DBAs) and transients for the AFW System are as follows:

a. Feedwater Line Break (FWLB); and

b. Loss of main feedwater (MFW).

In addition, the minimum available AFW flow and system characteristics are serious considerations in the analysis of a small break loss of coolant accident (LOCA).

(continued)

BASES

APPLICABLE SAFETY ANALYSIS (continued)

The AFW System design is such that, in the event of a complete loss of offsite power, decay heat removal would continue to be assured by the availability of either the turbine driven AFW pump, or one of the two motor driven AFW pumps, along with steam discharge to the atmosphere through the MSSVs.

The AFW System actuation instrumentation satisfies Criterion 3 of the NRC Policy Statement.

LCO

This LCO provides assurance that the AFW System will perform its design safety function to mitigate the consequences of accidents that could result in overpressurization of the reactor coolant pressure boundary.

The LCO requires all instrumentation performing an AFW System actuation function to be OPERABLE. Failure of any instrument renders the affected channel(s) inoperable and reduces the reliability of the affected Functions.

The required channels of AFW System actuation instrumentation provide unit protection in the event of any of the analyzed accidents. AFW System actuation instrumentation protection functions are as follows:

1. Steam Generator Water Level – Low Low

   SG Water Level – Low Low provides protection against a loss of heat sink. A feed line break, inside or outside of containment, or a loss of MFW, would result in a loss of SG water level. SG Water Level – Low Low provides input to the SG Level Control System. Two-out-of-three signals on one SG will start the motor driven AFW pumps. Two-out-of-three signals on two SGs will start the steam driven AFW pump. Thus, three OPERABLE channels are required to satisfy the requirements with two-out-of-three logic.

2. Safety Injection (SI)

   An SI signal starts the two motor driven AFW pumps. The AFW initiation functions are the same as the

(continued)

BASES

LCO

1. Steam Generator Water Level – Low Low (continued)

requirements for their SI function. Therefore, the requirements are not repeated in Table 3.3.8-1. Instead, Table 3.3.2-1, Function 1 (Safety Injection), is referenced for all initiating functions and requirements.

3. Loss of Offsite Power

A loss of offsite power to the 480 V emergency busses will be accompanied by a loss of MFW and reactor coolant pumping power, and the subsequent need for some method of decay heat removal. Loss of offsite power is detected by undervoltage relays sensing the voltage on each 480 volt emergency (E) bus. Loss of power to either emergency bus will start the motor driven AFW pumps in the station blackout loading sequence 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. A loss of power to the E1 bus initiates a start of the "A" AFW pump and a loss of power to the E2 bus initiates a start of the "B" AFW pump. The relays are arranged in a one-out-of-two logic, such that either relay will generate a loss of power (LOP) signal if the voltage is below the setpoint for a short period of time. The LOP signal also initiates starting the emergency diesel generators as described in the bases to LCO 3.3.5, "Loss of Power (LOP) Diesel Generator (DG) Start Instrumentation."

4. Undervoltage- Reactor Coolant Pump (RCP)

A loss of power on 4 kV buses 1 and 4, which provide power to both MFW pumps and two RCPs, provides indication of a loss of MFW and forced flow in the RCS. Two sensors are provided on each bus, with two-out-of-two logic on both busses required to start the turbine driven AFW pump 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.

(continued)

BASES

LCO (continued)

5. Trip of All Main Feedwater Pumps

A Trip of both MFW pumps is an indication of a loss of MFW and the subsequent need for some method of decay heat and sensible heat removal to bring the reactor back to no load temperature and pressure conditions. One contact on each MFW pump circuit breaker position provides input to the actuation logic that starts the motor driven AFW pumps. A trip of both MFW pumps starts the two motor driven AFW pumps to ensure that at least one SG is available with water to act as the heat sink for the reactor.

APPLICABILITY

Functions 1 through 4 must be OPERABLE in MODES 1, 2, and 3 to ensure that the SGs remain the heat sink for the reactor. 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 automatic 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 will be available to manually place either system in operation.

Function 5 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 an accident. In MODES 3, 4, and 5, the MFW pumps may be normally shut down, and thus neither pump trip is indicative of a condition requiring automatic AFW actuation.

ACTIONS

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 on Table 3.3.8-1.

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 Function(s) affected. When

(continued)

BASES

ACTIONS (continued)

the Required Channels in Table 3.3.8-1 are specified (e.g., on a per bus or per pump basis), then the Condition may be entered separately for each bus or pump, etc., as appropriate.

A.1

Condition A applies to all AFW Functions, and 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 3.3.8-1 and to take the Required Actions for the 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 Undervoltage-Reactor Coolant Pump. If one channel is inoperable, 4 hours are allowed to restore the channel to OPERABLE status or to place it in the tripped condition. A failure of one Undervoltage-Reactor Coolant Pump channel places the Function in an unacceptable configuration. The inoperable channel must be tripped to place the Function in a one-out-of-one coincident with a two-out-of-two configuration.

Failure to restore the inoperable channel to OPERABLE status or place it in the tripped condition within 4 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.

C.1, C.2.1, and C.2.2

Condition C applies to 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. A failure of one SG Water Level-Low Low channel

(continued)

BASES

ACTIONS

C.1, C.2.1, and C.2.2 (continued)

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.

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.

D.1, D.2.1, and D.2.2

Condition D applies to Loss of Offsite Power. This action recognizes the lack of manual trip provision for a failed channel. If a channel is inoperable, 48 hours are allowed to return it to OPERABLE status. The specified Completion Time is reasonable considering the nature of this Function, the available redundancy, and the low probability of an event occurring during this interval. If the Function 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.

E.1 and E.2

Condition E applies to the AFW pump start on trip of all MFW pumps. This action addresses the relay logic for the auto start function of the AFW System on loss of all MFW pumps. The OPERABILITY of the AFW System must be assured by allowing automatic start of the AFW System pumps. If a channel is inoperable, 48 hours are allowed to return it to

(continued)

BASES

ACTIONS

E.1 and E.2 (continued)

an OPERABLE status. If the Function cannot be returned to an OPERABLE status, 6 hours are allowed 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. The allowance of 48 hours to return the train to an OPERABLE status is justified in WCAP-10271-P-A (Ref. 3).

SURVEILLANCE REQUIREMENTS

The SRs for each AFW Actuation Function are identified by the SRs column of Table 3.3.8-1.

A Note has been added to the SR Table to clarify that Table 3.3.8-1 determines which SRs apply to which Functions.

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 3.3.8.1

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 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.

Channel deviation 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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.8.1 (continued)

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 3.3.8.2

SR 3.3.8.2 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 tolerances and Allowable Values specified in Table 3.3.8-1.

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 (Ref. 4). The setpoint must be left set consistent with the assumptions of the setpoint methodology (Ref. 4).

The "as found" and "as left" values must also be recorded and reviewed for consistency with the assumptions of the surveillance interval extension analysis in Reference 3 when applicable.

The Frequency of 92 days is justified in Reference 3.

SR 3.3.8.3

SR 3.3.8.3 is the performance of a TADOT. This test is a check of AFW automatic pump start on loss of offsite power, undervoltage RCP, and trip of all MFW pumps Functions. It is performed every 18 months. Each applicable Actuation Function is tested up to, and including, the end device start circuitry. In some instances, the test includes actuation of the end device (i.e., pump starts, valve cycles, etc.). As noted, this SR requires the injection of a simulated or actual signal for the Trip of Main Feedwater

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.8.3 (continued)

Pumps Function. The injection of the signal should be as close to the sensor as practical. The Frequency is adequate, based on industry operating experience and is consistent with the typical refueling cycle.

SR 3.3.8.4

SR 3.3.8.4 is the performance of a CHANNEL CALIBRATION. A CHANNEL CALIBRATION is performed every 18 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. 9). 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 (Ref. 9).

The Frequency of 18 months is based on the assumption of an 18 month calibration interval in the determination of the magnitude of equipment drift in the setpoint methodology (Ref. 9).

REFERENCES

1. UFSAR, Section 7.3.1

2. UFSAR, Section 3.1

3. WCAP-10271-P-A, Supplement 2, Rev. 1., June 1990

4. Attachment VIII to CPL's letter to NRC dated May 30, 1997, H. B. Robinson Steam Electric Plant, Unit No. 2 - Response to Request for Additional Information and Transmittal of Supplement 4 Regarding the Technical Specification Change Request to Convert to the Improved Standard Technical Specification.

SUPPLEMENT 8
CONVERSION PACKAGE SECTION 3.4
PAGE INSERTION INSTRUCTIONS

Remove and insert the following pages into Enclosure 12 to Serial: RNP-RA/96-0141.

	Remove Page	Insert Page
a.	Part 1, "Markup of Current Technical Specifications (CTS)"	
	3.1-4 (3.4.12)	3.1-4 (3.4.12)
b.	Part 2, "Discussion of Changes (DOCs) for CTS Markup"	
	20, 21, 23	20, 21, 23
	26a	26a
	29 through 36	29 through 38
c.	Part 3, "No significant Hazards Consideration (NSHC), And Basis for Categorical Exclusion from 10 CFR 51.22"	
	22d, 22e	22d, 22e
d.	Part 4, "Markup of NUREG-1431, Revision 1, Standard Technical Specifications Westinghouse Plants, (ISTS)"	
	ITS Insert 3.4.12-1 (page 3.4-27a)	ITS Insert 3.4.12-1 (page 3.4-27a)
	3.4-50	3.4-50
e.	Part 5, "Justification of Differences (JFDs) to ISTS"	
	-	8
f.	Part 6, "Markup of ISTS Bases"	
	ITS Insert B 3.4.12-1 (page B 3.4-58a)	ITS Insert B 3.4.12-1 (page B 3.4-58a)
	ITS Insert B 3.4.12-1a (page B 3.4-59a)	ITS Insert B 3.4.12-1a (page B 3.4-59a)
	B 3.4-65, B 3.4-72	B 3.4-65, B 3.4-72
	ITS Insert B 3.4.12-10 through 12 (page B 3.4-72A)	ITS Insert B 3.4.12-10 through 12 (page B 3.4-72A)
	Insert B 3.4.17-1 (pages B 3.4-102 through B 3.4-104)	Insert B 3.4.17-1 (pages B 3.4-102 through B 3.4-104)
g.	Part 7, "Justification of Differences (JFDs) to ISTS Bases"	
	NA	
h.	Part 8, "Proposed HBRSEP, Unit No. 2 ITS"	
	3.4-29, 3.4-50	3.4-29, 3.4-50

SUPPLEMENT 8
CONVERSION PACKAGE SECTION 3.4
PAGE INSERTION INSTRUCTIONS

Remove and insert the following pages into Enclosure 12 to Serial: RNP-RA/96-0141.

	Remove Page	Insert Page
i.	Part 9, "Proposed Bases to HBRSEP, Unit No. 2 ITS"	
	B 3.4-60, B 3.4-62	B 3.4-60, B 3.4-62
	-	B 3.4-62a
	B 3.4-67, B 3.4-74, B 3.4-80,	B 3.4-67, B 3.4-74, B 3.4-80,
	B 3.4-102, B 3.4-103, B 3.4-104	B 3.4-102, B 3.4-103, B 3.4-104
j.	Part 10, "ISTS Generic Changes"	
	NA	

ITS

A1

3.1.2 Heatup and Cooldown

3.1.2.1 The reactor coolant pressure and the system heatup and cooldown rates (with the exception of the pressurizer) shall be limited in accordance with Figure 3.1-1 and Figure 3.1-2 (for vessel exposure up to 24 EFPY). These limitations are as follows:

a. Over the temperature range from cold shutdown to hot operating conditions, the heatup rate shall not exceed 60°F/hr. in any one hour.

See 3.4.3

b. Allowable combinations of pressure and temperature for a specific cooldown rate are below and to the right of the limit lines for that rate as shown on Figure 3.1-2. This rate shall not exceed 100°F/hr. in any one hour. The limit lines for cooling rates between those shown in Figure 3.1-2 may be obtained by interpolation.

c. Primary system hydrostatic leak tests may be performed as necessary, provided the temperature limitation as noted on Figure 3.1-1 is not violated. Maximum hydrostatic test pressure should remain below 2350 psia.

[LCO 3.4.12.a.1] d. The overpressure protection system shall be OPERABLE[1], with both power operated relief valves OPERABLE with a lift setting of ~~less than or equal to~~ 420 psi whenever any RCS

nominal

9

M35

400 psig and an allowable value of ≤ 418 (PORVs with lift settings, found between CHANNEL CALIBRATIONS, greater than the nominal lift setting but less than the allowable value are OPERABLE

[1] The overpressure protection system shall not be considered inoperable solely because either the normal or emergency power source for the PORV block valves is inoperable.

A8

Supplement 8

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 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 3.4.15.4 requires the performance of a CHANNEL CALIBRATION for each of the containment atmosphere radiation monitor instrumentation channel. The calibration verifies the accuracy of the instrument string. The Frequency of 18 months is a typical refueling cycle and considers channel reliability. Again, operating experience has proven that this Frequency is acceptable. This change constitutes a more restrictive change necessary to help ensure these instruments are maintained OPERABLE.

M33 Not Used.

M34 Not Used

M35 CTS Specification 3.1.2.1.d, which requires that the LTOP setpoint be less than or equal to 420 psig, is revised in LCO 3.4.12.a.1 to require the nominal lift setting to be 400 psig and the allowable value to be ≤ 418 psig. The lower setting, of the ITS LCO 3.4.12.a.1 allowable value, is necessary to support the overpressure transient analysis that permits utilization of a single OPERABLE SI train in MODE 4. The allowable value imposes a maximum allowable drift for the nominal lift setting that was not previously included in the CTS. As stated in the CP&L Letter dated February 18, 1997, the actual nominal lift setting entered into the bistable is more conservative than that specified by the allowable value to account for changes in random measurement errors

detectable by a Channel Operational Test (COT). One example of such a change in measurement error is drift during the surveillance interval. If the measured lift setting does not exceed the allowable value, the channel is considered OPERABLE.

This change therefore imposes more restrictive requirements, and has no adverse impact on safety.

M36 CTS Specification 3.1.1.2 requires two steam generators to be operable whenever the average primary coolant temperature is above 350°F. ITS Specification 3.4.5 requires two RCS loops to be OPERABLE in MODE 3. The ITS Bases for Specification 3.4.5 describes that an OPERABLE RCS loop consists of one OPERABLE reactor coolant pump and one OPERABLE steam generator in accordance with the Steam Generator Tube Surveillance Program, which has a water level within required limits. This LCO ensures forced circulation of the reactor coolant to remove decay heat from the core and to provide proper boron mixing. As a result, the ITS Specification 3.4.5 requirement constitutes an additional restriction on plant operation necessary to help ensure decay heat removal capability is maintained.

M37 CTS Specification 3.1.2.1.d requires the overpressure protection system to be OPERABLE whenever RCS temperature is less than or equal to 350°F and the reactor vessel head is on the reactor vessel and the RCS is not vented. Implicit in CTS Specification 3.1.2.1.d is the allowance that adequate overpressure protection is provided by removal of the reactor vessel head or venting the RCS. ITS Specification 3.4.12.b is added to provide the details of what constitutes acceptable low temperature overpressure protection (the RCS depressurized and an RCS vent of $\geq$ 4.4 square inches). Adding these details into the Technical Specifications represents an additional restriction on unit operation and is necessary to ensure protection of the reactor coolant pressure boundary from a low temperature overpressure event. The 4.4 square inch vent size is based upon an analysis assuming a mass input from two safety injection pumps, three charging pumps and the RHR system in operation aligned for shutdown cooling. Under these circumstances, the ASME Appendix G limit will not be reached.

M38 The CTS is revised by adopting ISTS Specification 3.4.5 LCO "Note," Specification 3.4.6 LCO "Note 1," and Specification 3.4.7 LCO "Note 1." These Notes permit all RCPs or RHR pumps to be de-energized for up to 1 hour in any 8 hour period, to permit tests that are designed to validate various accident analyses values. CTS Specification 3.1.1.1.a currently allows operation with less than two RCPs in operation when the conditions set forth in CTS Specifications 3.1.1.1.a.1, 3.1.1.1.a.2, and 3.1.1.1.a.3 are met. The CTS has no time restriction for operation in this condition. Because these notes impose a time restriction on operation with one or no RCPs in operation, this change is a more restrictive change. This change is acceptable, however, because

TECHNICAL CHANGES - LESS RESTRICTIVE (GENERIC)

LA1 CTS Specifications 3.1.2.1.a, 3.1.2.1.b, 3.1.2.1.c, and 3.1.2.4 provide limitations on use of, and instructions for updating the pressure and temperature (P/T) limit curves (CTS Figures 3.1-1 and 3.1-2). This detail is not retained in the ITS and is relocated to the Bases to ITS LCO 3.4.3 and the reporting requirements to the UFSAR.

The details associated with the involved Specifications are not required to be in the ITS to provide adequate protection of the public health and safety, since the ITS still retains the RCS heatup and cooldown rate requirements. This approach provides an effective level of regulatory control and provides for a more appropriate change control process. The level of safety of facility operation is unaffected by the change because there is no change in the overall operational requirements. Furthermore, NRC and licensee resources associated with processing license amendments to these requirements will be reduced. Therefore, relocation of these details is acceptable.

LA2 CTS Specification 3.1.1.1.a.1 requires that a shutdown margin of at least 4% $\Delta k/k$ be maintained. This detail is not retained in the ITS and is relocated to the Core Operating Limits Report (COLR). The COLR includes the methodology for SDM limit determinations as identified in ITS Chapter 5.0.

The details associated with the involved Specifications are not required to be in the ITS to provide adequate protection of the public health and safety, since the ITS still retains the requirement that the shutdown margin be maintained within the limits specified in the COLR. This approach provides an effective level of regulatory control and provides for a more appropriate change control process. The level of safety of facility operation is unaffected by the change because there is no change in the overall operational requirements. Furthermore, NRC and licensee resources associated with processing license amendments to these requirements will be reduced. Therefore, relocation of these details is acceptable.

LA3 CTS Specification 3.1.1.3.a requires that one pressurizer safety valve be OPERABLE whenever the reactor head is on the vessel, and the RCS is not open for maintenance. This detail is not retained in the ITS and is relocated to licensee controlled documents.

The details associated with the involved Specifications are not required to be in the ITS to provide adequate protection of the public health and safety, since the ITS still retains Low Temperature Overpressure Protection (LTOP) requirements. This approach provides an effective level of regulatory control and provides for a more appropriate change control process. The level of safety of facility operation is unaffected by the change because there is no change in the overall

LA11 CTS Specification 3.2.1 requires a flow path for boric acid injection equivalent to that supplied from the RWST in all plant conditions when fuel is in the reactor. This requirement is not retained in the ITS and is relocated to the Technical Requirements Manual.

The requirement is not required to be in the ITS to provide adequate protection of the public health and safety, since other ITS LCO requirements provide adequate protection. ITS LCO 3.1.1 requires that a shutdown margin be maintained in all MODES except MODE 1 and MODE 2 with $K_{eff} \geq 1.0$. ITS LCO 3.9.1 requires that boron concentrations in the RCS be within the limits specified by the COLR in MODE 6. ITS LCOs 3.1.1 and 3.9.1 provide an adequate basis for maintaining boron concentration at required levels. As stated in WCAP-11618, "Methodically Engineered, Restructured and Improved Technical Specifications," Westinghouse Electric Corporation, November 1987, the response to a malfunction of the CVCS, which causes a boron dilution event, is to close the appropriate valves in the reactor makeup system. This action is required before the shutdown margin is lost. Since the boron addition capability is not assumed to function to mitigate the consequences of any analyzed accident the CTS Specification for a boric acid addition pathway is a detail that is relocated to licensee controlled documents.

This approach provides an effective level of regulatory control and provides for a more appropriate change control process. The level of safety of facility operation is unaffected by the change because there is no change in the overall operational requirements. Furthermore, NRC and licensee resources associated with processing license amendments to these requirements will be reduced. Therefore, relocation of these requirements is acceptable.

LA12 CTS Specification 3.2.2, Items b and c require both boric acid transfer pumps be operable and that the boric acid tanks contain a minimum volume and concentration of boric acid. CTS Specification 3.2.2, Items e and f require two channels of heat tracing to be operable for the flow path from the boric acid tanks and that the primary water storage tank contain a minimum volume. The corresponding actions are provided in CTS Specification 3.2.3, items b and c.

These requirements for component operability provide a means of assuring an operable boron injection capability into the RCS. These requirements are not required to be in the ITS to provide adequate protection of the public health and safety, since other ITS LCO requirements provide adequate protection. ITS LCO 3.1.1 requires that a shutdown margin be maintained in all MODES except MODE 1 and MODE 2 with $K_{eff} \geq 1.0$. ITS LCO 3.9.1 requires that boron concentrations in the RCS be within the limits specified by the COLR in MODE 6. ITS LCOs 3.1.1 and 3.9.1 provide an adequate basis for maintaining boron concentration at required levels. As stated in WCAP-11618, "Methodically Engineered,

such that natural circulation can be achieved. Actions to ensure these conditions are present, prior to assuming the SG is capable of replacing an RHR loop, are contained in the normal operating procedures and are not provided in the specification. This change provides more flexibility in operation, and is therefore less restrictive. This change is acceptable, however, because with either choice, redundant decay heat removal systems are OPERABLE and available for use. 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 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 are specified as a backup means for redundancy when the RCS is not vented. 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. This change is consistent with NUREG-1431.

L7 CTS Specification 3.1.1.3.c.1 requires that pressurizer code safety valve lift settings be between 2485 psig and 2560 psig. ITS Specification 3.4.10 requires that safety valve lift settings be between 2410 psig and 2560 psig. This is a relaxation of requirements, and is less restrictive. This change is acceptable, however, since the same level of overpressure protection is provided. The wider OPERABILITY range of 2485 psig ± 3% allows for drift during valve setpoint test intervals, as permitted by Section III of the ASME Code. During setpoint testing, the valves are reset to 2485 psig ± 1%, as required by Section XI of the ASME Code. This change is consistent with NUREG-1431.

L8 CTS Specification 3.3.1.3 requires that the SI pump breakers be racked out when RCS temperature is below 350°F and the system is not vented to containment atmosphere. ITS LCO 3.4.12.a.2 requires all but one SI pump to be made incapable of injecting into the RCS when the RCS temperature is ≥ 175°F. This is a relaxation of requirements, and is less restrictive. This change is acceptable based on a new overpressure protection analysis that has been performed to allow OPERABILITY of one train of SI in MODE 4. This analysis assumes one SI pump capable of injection into the RCS with RCS temperature ≥ 175°F and < 350°F.

L9 CTS Specification 3.1.1.3.c, which requires that all three pressurizer code safety valves be operable when RCS temperature is above 350°F, is revised to add ITS LCO 3.4.10 NOTE, which allows the safety valve lift settings to be outside the LCO limits for the purpose of setting the safety valves under ambient (hot) conditions. Because this note allows the pressurizer safety valves to be potentially inoperable in MODE 3 until the safety valves can be tested and set, this change is less restrictive. This change is acceptable because the limitations included

in the note (i.e., a maximum of 54 hours allowed following entry into MODE 3) assure that reactor decay heat is significantly reduced below the assumptions in the applicable safety analyses for LCO 3.4.10 (i.e., uncontrolled rod withdrawal from full power, loss of reactor coolant flow, loss of external electrical load, loss of normal feedwater, loss of all AC power to station auxiliaries, and a RCP locked rotor accident). 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 reasonable based on 18 hour outage time for each of the three valves. The 18 hour period is derived from operating experience that hot testing can be performed in this time frame.

L10 CTS Specification 3.1.5.3 requires that the unit be placed in cold shutdown within 30 hours of detection of exceeding primary to secondary leakage limits. ITS Specification 3.4.13 requires that the leakage be returned to within limits in 4 hours or be in MODE 3 in 6 hours and in MODE 5 in 36 hours. This is a relaxation of requirements, and is less restrictive. This change is acceptable, however, because it provides time to investigate and verify the leakage rates and attempt to reduce leakage to within limits before being required to shut down the reactor. This action is necessary to prevent further deterioration of the RCPB. The additional time allowed to achieve cold shutdown is also acceptable because it has been shown to be a reasonable time, based on industry operating experience, to reach MODE 5 from full power conditions in an orderly manner, and without challenging plant systems, and considers the low probability of further degradation of the RCPB in the additional time interval. This change is consistent with NUREG-1431.

L11 CTS Table 4.1-3 (Item 9) requires that RCS leakage be evaluated "daily" when the RCS is above the cold shutdown condition. ITS Specification 3.4.13 requires verifying RCS operational LEAKAGE is within limits by performance of an RCS water inventory balance "Once within 12 hours after reaching steady state operation conditions <u>and</u> 72 hours thereafter during steady state operation." This is a relaxation of requirements, and is less restrictive. This change is acceptable, however, since an early warning of pressure boundary leakage or unidentified leakage is provided by the automatic systems that monitor containment radioactivity and containment sump level. The leakage detection system operability requirements are specified in ITS Specification 3.4.15. Additionally, the more restrictive Completion Time requirements for the Required Actions associated with ITS Specification 3.4.13, together with the SR 3.4.13.1 requirement to perform an RCS water inventory balance on a 72 hour frequency, provide assurance that operational leakage is closely monitored.

The RCS water inventory balance must be met with the reactor at steady state operating conditions. 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 operation is established. For RCS operational LEAKAGE determination by water inventory balance, steady state operation is defined as stable RCS pressure, temperature, power level, pressurizer and makeup tank levels, makeup and letdown, and RCP seal injection and return flows. Therefore, the initial performance of this SR within 12 hours after reaching continuous steady state operation is acceptable. This change is consistent with NUREG-1431.

L12 CTS Specification 3.1.5.4.b requires that, with leakage from any pressure isolation valve (PIV) not within limits, operation may continue provided that at least two valves are in, and remain in, the mode corresponding to the isolated condition. ITS Specification 3.4.14 requires initial isolation of the high pressure line by a single valve within 4 hours, and by a second valve within 72 hours. This is a relaxation of requirements, and is less restrictive. This change is acceptable, however, because the CTS Specification has no completion time associated with the required actions. The extended interval is also acceptable because it is based on the time usually required to perform this action and considers the low probability of another valve failing during this period. This change is consistent with NUREG-1431.

L13 CTS Table 4.1-3, Item 17.1, requires that PIV leakage be verified prior to entering reactor operation whenever the unit has been in cold shutdown for 72 hours. ITS Specification 3.4.14 requires that PIV leakage be verified whenever the unit has been in MODE 5 for 7 days or more. The intent of this provision in the Frequency is to avoid extending a brief shutdown for PIV testing. Since the result of this change is a net reduction in the number of times that PIV leakage verification would be expected to be required over the remaining life of the plant, it is a relaxation of requirements, and is less restrictive. This change is acceptable, however, since PIV leakage verification is performed routinely at an 18 month frequency, and HBRSEP historical leakage verification experience has shown that the PIVs usually pass the Surveillances when performed at the specified Frequency. In addition, the plant conditions and test results associated with performing the PIV leakage testing are not affected whether the tests are conducted after 72 hours or after 7 days. Consequently, the Frequency is concluded to be acceptable from a reliability standpoint. This change is consistent with NUREG-1431.

L14 CTS Specification 3.1.4 requires that RCS specific activity be maintained within limits in "all modes," and "any operating mode." ITS Specification 3.4.16 is applicable in MODES 1 and 2; and MODE 3 with RCS average temperature (T_{avg}) $\geq$ 500°F. Since the CTS applicability is "all modes" and "any operating condition," when the specific activity of the

primary coolant exceeds the limits for dose equivalent iodine 131 or gross activity, CTS 3.1.4 requires the sampling and analysis requirements of table 4.1-2 be performed until the specific activity of the primary coolant is restored to within limits. ITS 3.4.16 Required Actions requirements are no longer applicable when the unit is no longer in the MODES or other conditions stated in the Applicability for the LCO. Additionally, when the limit is exceeded limit for gross activity, ITS 3.4.16 RA B.1 requires the unit be placed outside the MODE of Applicability within 6 hours without imposing any additional sampling and analysis requirement. This is a relaxation of requirements, and is less restrictive. This change is acceptable, however, because the LCO limits for DOSE EQUIVALENT I-131 and gross specific activity when operating in MODES 1 and 2, and in MODE 3 with RCS average temperature ≥ 500°F, are necessary to contain the potential consequences of a steam generator tube rupture (SGTR) to within the acceptable site boundary dose values. When the unit is operating in MODE 3 with RCS average temperature < 500°F, and in MODES 4 and 5, the release of radioactivity in the event of an SGTR is unlikely, since the saturation pressure of the reactor coolant is below the lift pressure settings of the main steam safety valves. Exiting the MODES of applicability eliminates requirements for additional sampling and analyses. This change is consistent with NUREG-1431.

L15 CTS Table 4.1-2, Item 1, requires that reactor coolant samples be analyzed for gross activity at least every 72 hours. ITS Specification 3.4.16 requires that analysis be performed at a frequency of 7 days. This is a relaxation of requirements, and is less restrictive. This change is acceptable, however, because the analysis provides an indication of any increase in gross specific activity, and trending the results of these analyses allows for proper remedial action to be taken before reaching the LCO limit under normal operating conditions. The relaxation of the surveillance frequency from 3 days to 7 days also considers the unlikelihood of a gross fuel failure during the extended interval. This change is consistent with NUREG-1431.

L16 CTS Specification 3.3.1.4.a contains a requirement that, under certain conditions, a Special Report be prepared and submitted to the NRC within 30 days. This requirement is not retained in the ITS. This is a relaxation of requirements, which is less restrictive. This change is acceptable, however, since this report covers incidents that have already occurred, and there is no requirement for the NRC to approve the report. Completion and submittal of the report is clearly not necessary to ensure safe operation of the unit after the condition has occurred. This change is consistent with NUREG-1431.

L17 CTS Specification 3.3.1.4.a requires that, in the event of an inoperable RHR loop, the existence of a method to add make-up water to the RCS be verified within 24 hours, and the RHR loop be restored to operable status within 14 days. ITS Specifications 3.4.7 and 3.4.8 require

instead, that action be initiated immediately to restore a second RHR train to operable status. This change imposes less restrictive requirements because there are no requirements in the ITS to restore the inoperable RHR train or to verify a method to add make-up water. These changes are acceptable because the end result is the same, an RHR train is restored to OPERABLE and operating status in order to satisfy the LCO. This change is consistent with NUREG-1431.

L18 CTS Specification 3.1.1.2 requires two steam generators to be operable whenever the average primary coolant temperature is above 350°F. For the condition of an inoperable steam generator, no explicit allowed outage time is provided. As a result, in this condition entry into CTS 3.0 would be required. CTS 3.0 requires the unit to be placed in hot shutdown within 8 hours and to be placed in cold shutdown within the next 30 hours until the reactor is placed in a condition in which the specification is not applicable. For the same condition, ITS Specification 3.4.5 Required Action A.1 provides an allowed outage of time of 72 hours. If the inoperable component is not restored to OPERABLE status within 72 hours, ITS Specification 3.4.5 Required Action B.1 requires that the unit be placed in MODE 4 (which is outside the Applicability of Specification 3.4.5) within 12 hours. The addition of a Required Action Completion Time of 12 hours to reach MODE for is a more restrictive aspect of this change. In this condition, the remaining OPERABLE and operating RCS loop is adequate to provide the decay heat removal function, ensure that boron stratification does not occur. In addition, the requirements imposed by the LCO when only one RCS loop is operating are adequate to ensure a power excursion resulting from an inadvertent control rod withdrawal event is precluded. However, in this condition, a single failure may place the unit in a condition where adequate decay heat removal and proper mixing of the reactor coolant may not be available. Therefore, an allowable outage time of 72 hours is provided; after which the unit must be placed in MODE 4 within the next 12 hours. These time periods ensure the risk associated with unit operation in this condition is minimized while providing an allowance to attempt restoration prior to subjecting the unit to a cooldown transient. This change is consistent with NUREG-1431.

L19 CTS Specification 3.1.1.1.a allows the number of operating reactor coolant pumps to be reduced provided certain actions are taken. These actions ensure that a power excursion resulting from a inadvertent control rod withdrawal event is precluded. CTS Specification 3.1.1.1.a does not explicitly provide a time period for implementing these requirements in the event of a loss of an operating reactor coolant pump. ITS Specification 3.4.5 Required Action C.1 provides an allowable outage time of 1 hour to comply with the requirements of the LCO. This time period is adequate to be restore compliance with the LCO without exposing the unit to risk for an undue period of time. In addition, this time period is consistent with the 1 hour time provided in ITS LCO 3.0.3 before requiring the unit to be placed in a non-applicable MODE.

L20 The CTS is modified by the addition of ITS LCO 3.4.17 Required Actions D.1, D.2, and D.3 to require that in the event that seal injection to any RCP is not within limits and both required charging pumps are inoperable, the plant be cooled down and depressurized to an RCS pressure < 1400 psig. No comparable action is contained in CTS, and in such a condition, entry into CTS 3.0 would be required, which requires that the plant be placed in hot shutdown within 8 hours and in cold shutdown within an additional 30 hours. The ITS 3.4.17 Required Actions associated with ITS 3.4.17 Condition D are a relaxation of requirements and is more appropriate than requiring entry into cold shutdown. If ITS Condition D were entered, seal injection to the RCPs is not assured. Cooling of the RCPs is only available from the component cooling system, and if the component cooling system were lost, RCP seal failure would eventially occur if seal injection or component cooling were not restored. When no charging capability is available, the RCS will lose RCS inventory through the RCP seals. With no operable means of RCP seal injection, it would be imprudent to require the plant to go to MODE 4, where a requirement for RCP seal injection remains and shutdown margin requirements would be difficult to maintain. Therefore, the appropriate action is to initiate measures to restore RCP seal injection immediately and to continue the action to cool down and depressurize to an RCS pressure less than 1400 psig to allow makeup to the RCS through the Safety Injection (SI) System. The Completion Time of 12 hours is reasonable based on operating experience to allow an orderly transition between MODES 3 and MODE 4, which is the closest condition corresponding to depressurization to an RCS pressure < 1400 psig, without challenging plant systems. Maintaining the plant in MODE 3 with the RCS pressure < 1400 psig until charging is reestablished to the RCPs is reasonable to avoid further challenging plant systems in this condition.

L21 CTS Specification 3.2.2.d requires that system piping, instrumentation, controls, and valves shall be operable to the extent of establishing one flow path from the BASTs and one flow path from the RWST to the RCS. This requirement is modified in ITS LCO 3.4.17 as the requirement that two Makeup Water Pathways from the RWST shall be OPERABLE. The ITS provides more operational flexibility and is less restrictive because the BASTs are not specified to be a pathway source. There are two pathways available from the RWST to the charging pump suction header, any one of which provides an equivalent source of makeup water for RCP seal injection. The Operability requirement for ITS Specifications 3.4.17 is to maintain sufficient seal water injection flow to the RCPs. Two pathways provide redundant capability to assure a continuous source of makeup water without specifying each pathway source. Therefore, the increased flexibility in ITS Specifications 3.4.17 is acceptable.

L22 Not Used.

L23 CTS Specification 3.2.3.a allows one boric acid transfer pump to be inoperable for up to 24 hours. CTS Specification 3.2.3.c allows one channel of heat tracing to be inoperable for up to 24 hours. The CTS is modified by not including these specific requirements and by adding ITS LCO 3.4.17 Required Action B.1 which allows a Makeup Water Pathway from the RWST to be inoperable for up to 24 hours. This change adds operational flexibility and is less restrictive because the allowable inoperable components in the Makeup Water Pathways are not specified and because there are no longer Required Actions for the boric acid pumps and heat tracing. There are two pathways available from the RWST to the charging pump suction header. These pathways consist of a remotely operated air operated valve and a locally operated manual valve. Either of these pathways provide an equivalent source of makeup water for RCP seal injection. The Operability requirement for ITS Specifications 3.4.17 is to maintain sufficient seal water injection flow to the RCPs. The two pathways provide redundant capability to assure a continuous source of makeup water without specifying each pathway source.

Additionally, other components than those named in CTS Specification 3.2.3 (i.e., valves) may be inoperable in the makeup water pathways that render the pathway inoperable. In such cases the CTS would require entry into CTS Specification 3.0, which requires that hot shutdown be achieved in 8 hours and cold shutdown be achieved within an additional 30 hours. The addition of ITS LCO 3.4.17 Required Action B.1 avoids entry into ITS Specification 3.0.3 for the valves. This change is acceptable because the allowed outage time places an ultimate time requirement that must be met to exit the Condition.

Therefore, the increased flexibility in ITS Specifications 3.4.17 Required Action B.1 is acceptable.

L24 CTS Table 4.1-3 item 17.2 requires, whenever the integrity of a RCS pressure isolation valve cannot be demonstrated, the integrity of the remaining valve to be determined and recorded daily. In this condition, CTS Table 4.1.3 item 17.2 also requires that the position of the other closed valve located in the high pressure piping to be recorded daily. Under this same condition, ITS 3.4.14, RCS Pressure Isolation Valves (PIVs), Required Actions A.1 and A.2 require isolation of the high pressure portion of the piping from the low pressure portion of the piping by the use of two valves. In addition, ITS 3.4.14 Required Actions A.1 and A.2 are modified by a Note that requires the valves used to meet the requirements of Required Actions A.1 and A.2 to satisfy the leakage criteria of SR 3.4.14.1 (i.e., integrity determined to be

acceptable) and that the valves be in the reactor coolant pressure boundary or high pressure portion of the piping.

The normal periodic surveillance frequency (ITS SR 3.4.14.1) for RCS PIV leakage testing provides adequate assurance of PIV OPERABILITY. Therefore, the CTS requirement to perform the surveillance (in order to record the continued integrity of the associated valves used to comply with Required Actions A.1 and A.2) once per day is deleted. If the Surveillance is not performed within the normal surveillance interval, compliance with the requirements of the Note to Required Actions A.1 and A.2 would not be satisfied for these valves and a shutdown per Required Actions C.1 and C.2 would be required (i.e., action taken to exit the Applicability of the LCO). If at any time it is discovered that the valves used to comply with Required Actions A.1 and A.2 did not satisfy the requirements of SR 3.4.14.1, Condition C must be immediately entered and Required Actions C.1 and C.2 taken. In addition, ITS 3.4.14 Required Actions A.1 and A.2 require isolation of the high pressure portion of the piping from the low pressure portion of the piping by the use of two valves. The additional valve required to provide isolation ensures that a single failure of one of these valves does not impact the ability to prevent overpressurization of low pressure piping. Therefore, the proposed change continues to provide adequate assurance that overpressurization of low pressure piping will not occur.

ITS 3.4.14 Required Actions A.1 and A.2 require isolation of the high pressure portion of the piping from the low pressure portion of the piping by the use of two valves. These requirements provide adequate assurance that the high pressure portion of the piping will remain isolated from the low pressure portion of the piping. Therefore, in the event of an inoperable RCS PIV, the CTS requirement to record the position of the other closed valve located in the high pressure piping daily (i.e., verification of compliance with Technical Specifications Actions) is deleted. This change is considered to be acceptable based on 1) the administrative controls governing valve operation, 2) the low probability of misalignment of these valves, and 3) the fact that ITS 3.4.14 Required Actions A.1 and A.2 require isolation of the high pressure portion of the piping from the low pressure portion of the piping by the use of two valves versus the CTS requirement to isolate the high pressure portion of the piping by the use of one valve. The CTS verification is an implicit part of using Technical Specifications and determining the appropriate Conditions to enter and Actions to take in the event of inoperability of Technical Specification equipment and the failure to comply with Technical Specification Actions. In addition, plant and equipment status is continuously monitored by control room personnel. The results of this monitoring process are documented in records/logs maintained by control room personnel. The continuous monitoring process includes re-evaluating the status of

compliance with Technical Specification requirements, when Technical Specification equipment status changes, using the control room records/logs as aids. Therefore, the explicit requirement to periodically record/verify, in the event of an inoperable RCS PIV, the position of the other closed valve located in the high pressure piping is considered to be unnecessary for ensuring compliance with the applicable Technical Specification Actions.

RELOCATED SPECIFICATIONS

R1	3.1.2.2	Steam Generator Pressure
	3.1.2.3	Pressurizer Heatup and Cooldown
	Table 4.1-2 Item 1	Oxygen and chloride concentration in the RCS

These Specifications, or Limiting Conditions for Operation (Chapter 3.0), are not retained in the ITS because they have been reviewed against, and determined not to satisfy, the selection criteria for Technical Specifications provided in 10 CFR 50.36. The selection criteria were established to ensure that the Technical Specifications are reserved for those conditions or limitations on plant operation considered necessary to limit the possibility of an abnormal situation or event that could result in an immediate threat to the health and safety of the public. The rationale for relocation of each of these Specifications is provided in the report, "Application of Selection Criteria to the H. B. Robinson Steam Electric Plant Unit No. 2 Technical Specifications."

These Limiting Conditions for Operation, and their associated Surveillance Requirements (Chapter 4.0), are relocated to licensee controlled documents. Relocation of the specific requirements for systems or variables contained in these Specifications to licensee documents will have no impact on the operability or maintenance of those systems or variables. The licensee will initially continue to meet the requirements contained in the relocated Specifications. The licensee is allowed to make changes to these requirements in accordance with the provisions of 10 CFR 50.59. Such changes can be made without prior NRC approval, if the change does not involve an unreviewed safety question, as defined in 10 CFR 50.59. These controls are considered adequate for assuring that structures, systems, and components in the relocated Specifications are maintained operable, and variables are maintained within limits. This change is consistent with the NRC Final Policy Statement on Technical Specification Improvements.

LESS RESTRICTIVE CHANGES
("L23" Labeled Comments/Discussions)

Carolina Power & Light Company has evaluated the proposed Technical Specification change and has concluded that it does not involve a significant hazards consideration. Although the criteria set forth in 10 CFR 50.92 applies to analyzed accidents, our conclusion also evaluated the risk significance from a loss of RCP Seal Water Injection as if it were an "analyzed accident" as discussed in the criteria set forth in 10 CFR 50.92. The bases for the conclusion that the proposed change does not involve a significant hazards consideration are discussed below.

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

   The proposed change does not involve any physical alteration of plant systems, structures or components or changes in parameters governing normal plant operation. The proposed change will provide an allowed outage time for any components within a pathway rather than for specified

components. Continuous operation with one pathway inoperable such that a single failure would preclude the pathways from fulfilling their required function is not allowed. Therefore, the significance of the increase in probability is small. The consequences of an accident occurring during the interval permitted in the allowed outage time for any one pathway are the same as the consequences during the currently permitted for a specific pathway. Therefore, the proposed change does not involve a significant increase in the probability or an increase in the consequences of an accident previously evaluated.

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

   The proposed change does not involve any physical alteration of plant systems, structures or components or changes in parameters governing normal plant operation. An increase in flexibility regarding redundancy for a Makeup Water Pathway does not create the possibility of any new or different kind of accident from any accident previously evaluated. Therefore, the possibility of a new or different kind of accident from any accident previously evaluated is not created.

3. Does this change involve a significant reduction in a margin of safety?

   The 24 hour allowed outage time for any inoperable Makeup Water Pathway is reasonable based on the redundant capabilities afforded by the OPERABLE pathway and the low probability of a loss of RCP seal injection occurring during this time period. However, the overall reliability is reduced because a single failure of the OPERABLE pathway could result in a loss of function. As a result, any reduction in the margin of safety is small and is at least partially offset by a reduction in the risk associated with averted plant shutdowns and associated shutdown transients. Therefore, the proposed change does not involve a significant reduction in a margin of safety.

LESS RESTRICTIVE CHANGES
("L24" Labeled Comments/Discussions)

Carolina Power & Light Company has evaluated the proposed Technical Specification change and has concluded it does not involve a significant hazards consideration. Our conclusion is in accordance with the criteria set forth in 10 CFR 50.92. The bases for the conclusion that the proposed change does not involve a significant hazards consideration are discussed below.

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

   The proposed change does not involve any physical alteration of plant systems, structures or components, changes in parameters governing normal

a. 1. Two power operated relief valves (PORVs) with nominal lift settings of 400 psig and allowable values of ≤ 418 psig (PORVs with lift settings, found between CHANNEL CALIBRATIONS, greater than the nominal lift setting but less than the allowable value are OPERABLE);

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2. A maximum of one Safety Injection (SI) pump capable of injecting into the RCS when all cold leg temperatures are ≥ 175°F; and

3. No SI pumps capable of injecting into the RCS when any cold leg temperature is < 175°F.

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.17 Chemical and Volume Control System (CVCS)

LCO 3.4.17 [M43] Reactor Coolant Pump (RCP) seal injection shall be OPERABLE, with:

[3.2.2.a] a. Two charging pumps shall be OPERABLE; and

[L21] b. Two Makeup Water Pathways from the Refueling Water Storage Tank (RWST) shall be OPERABLE.

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

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
[3.2.3.a] A. One required charging pump inoperable.	A.1 Restore required charging pump to OPERABLE status.	24 hours
[L23] B. One Makeup Water Pathway from the RWST inoperable.	B.1 Restore Makeup Water Pathway from the RWST to OPERABLE status.	24 hours
C. Required Action and associated Completion Time of Condition A or B not met. [3.2.3] [3.2.5]	C.1 Be in MODE 3. AND C.2 Be in MODE 5.	6 hours 36 hours

(continued)

37 In the ITS 3.4.12 (Low Temperature Overpressure Protection (LTOP) System), the term "lift settings" is modified to "nominal lift settings" and the inequality sign associated with the lift setting is removed. These changes are being made for consistency with the CP&L setpoint methodology and the associated discussions in the HBRSEP Unit No. 2 ITS Bases. The setpoint calculations performed for the affected setpoints using the CP&L setpoint methodology demonstrate that a PORV is OPERABLE if its lift setting, between CHANNEL CALIBRATIONS, exceeds the associated nominal lift setting but is within the allowable value. The setpoint calculations also demonstrate that if a PORV lift setting is within the established calibration tolerance band associated with the PORV lift setting, no adjustment of the PORV actuation channel's calibration is necessary to ensure the PORV is maintained OPERABLE for the length of the CHANNEL CALIBRATION interval. Therefore, the PORV lift settings are actually "nominal" values rather than "absolute" values. In addition, since this lift setting is a "nominal" value, the inequality sign associated with the lift setting in the ISTS is not necessary to ensure that the assumptions of the setpoint calculations and OPERABILITY of the associated PORVs are maintained.

ITS Insert B.3.4.12-1 (Low Temperature Overpressure Protection (LTOP) System)

The maximum allowed PORV lift setting (allowable value) for LTOP is derived by analyses which model the performance of the LTOP System, assuming various mass input and heat input transients. Operation with a PORV lift setting less than or equal to the allowable value ensures that Reference 1 criteria will not be violated with consideration for a maximum pressure over-shoot beyond the PORV lift setting which can occur as a result of time delays in signal processing and valve opening, instrument uncertainties, and single failure. The PORV lift settings and allowable values for the LTOP are updated based on the results of examinations of reactor vessel material irradiation surveillance specimens performed as required by 10 CFR 50, Appendix H.

ITS Insert B.3.4.12-1a (LTOP)

The nominal lift setting is the nominal value at which the LTOP bistable is set. The bistable is considered to be properly adjusted (in accordance with the nominal lift setting) when the "as left" value is within the established calibration tolerance band. A PORV lift setting is required to be adjusted, if the lift setting is found outside the established calibration tolerance band, such that the lift setting is within the established tolerance band. The nominal lift setting and allowable value are based upon the analytical limit (i.e., the 10 CFR 50, Appendix G limit, less effects for dynamic head of operating Reactor Coolant Pumps (RCPs) and RHR pumps, static head due to location of pressure transmitters, and the pressure overshoot due to the mass and heat addition overpressure events). To account for the calibration tolerances and instrument drift, which are assumed to occur between calibrations, statistical allowances are provided in the lift setting. The OPERABILITY of each transmitter or sensor can be evaluated when its "as found" calibration data are compared against its documented acceptance criteria. The LCO specifies both the nominal lift setting and an allowable value for the setting that represents the maximum allowable "as found" value for the instrument to be considered OPERABLE during calibration. The actual nominal lift setting entered into the bistable is more conservative than that specified by the allowable value to account for changes in random measurement errors detectable by a Channel Operational Test (COT). One example of such a change in measurement error is drift during the surveillance interval. Channels with lift settings, found between CHANNEL CALIBRATIONS, not within the nominal lift setting but within the allowable value are considered OPERABLE. A detailed description of the methodology used to calculate the trip setpoints, including their explicit uncertainties, is provided in the CP&L setpoint methodology procedure (Ref. 11) which is based upon current Instrument Society of America (ISA) standards.

BASES

APPLICABLE SAFETY ANALYSES

RCS Vent Performance (continued)

The LTOP System satisfies Criterion 2 of the NRC Policy Statement.

LCO

This LCO requires that the LTOP System is OPERABLE. The LTOP System 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.

Consistent with the assumptions of the analyses when the RCS is not depressurized and the RCS vent is not established

To limit the coolant input capability, the LCO requires [one] [HPI] pump [and one charging pump] capable of injecting into the RCS and all accumulator discharge isolation valves closed and immobilized when accumulator pressure is greater than or equal to the maximum RCS pressure for the existing RCS cold leg temperature allowed in the PTLR.

INSERT B 3.4.12-5

The elements of the LCO that provide low temperature overpressure mitigation through pressure relief are:

a. Two RCS relief valves, as follows:

1. Two OPERABLE PORVs; or

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.

[2. Two OPERABLE RHR suction relief valves; or]

An RHR suction relief valve is OPERABLE for LTOP when its RHR suction isolation valve and its RHR suction valve are open, its setpoint is at or between [436.5] psig and [463.5] psig, and testing has proven its ability to open at this setpoint.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

~~SR 3.4.12.8~~ (continued)

~~setting. The test must be performed within 12 hours after entering the LTOP MODES.~~

SR 3.4.12.9

Performance of a CHANNEL CALIBRATION on each required PORV actuation channel is required every 18 months to adjust the whole channel so that it responds and the valve opens within the required range and accuracy to known input.

REFERENCES

1. 10 CFR 50, Appendix G.
2. Generic Letter 88-11.
3. ~~ASME, Boiler and Pressure Vessel Code, Section III.~~
4. FSAR, Chapter 15
5. 10 CFR 50, Section 50.46.
6. 10 CFR 50, Appendix K.
7. Generic Letter 90-06.
8. ~~ASME, Boiler and Pressure Vessel Code, Section XI.~~

INSERT B3.4.12-10

INSERT B3.4.12-11

Insert B3.4.12-12

ITS Insert B.3.4.12-10 (LTOP System)

3. Letter, RNP-RA/96-0141, CP&L (R. M. Krich) to NRC, "Request for Technical Specifications Change, Conversion to Improved Standard Technical Specifications Consistent with NUREG-1431, 'Standard Technical Specifications-Westinghouse Plants,' Revision 1," August 30, 1996, Enclosure 5.

ITS Insert B.3.4.12-11 (LTOP System)

5. Letter, NG-77-1215, CP&L (B. J. Furr) to NRC (R. W. Reid), "Reactor Vessel Overpressurization Protection," October 31, 1977.

6. Letter, NG-77-1426, CP&L (E. E. Utley) to NRC (R. W. Reid), "Response to Overpressure Protection System Questions," December 15, 1977.

7. Report, "Pressure Mitigating Systems Transient Analysis Results," prepared by Westinghouse Electric Corporation for the Westinghouse Owners Group on Reactor Coolant System Overpressurization, July 1977, and Supplement, September 1977.

ITS Insert B.3.4.12-12 (LTOP System)

11. Attachment VIII to CPL's letter to NRC dated May 30, 1997, H. B. Robinson Steam Electric Plant, Unit No. 2 - Response to Request for Additional Information and Transmittal of Supplement 4 Regarding the Technical Specification Change Request to Convert to the Improved Standard Technical Specification.

Insert B3.4.17-1

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BASES

BACKGROUND
(continued)

Makeup water to the RCS is provided by the CVCS from the following sources:

a. The primary water storage tank, in combination with boric acid storage tanks provides water for makeup and RCS boron concentration adjustments, and

b The Refueling Water Storage Tank (RWST) which, via one of two pathways, supplies borated water for emergency makeup.

Three positive displacement charging pumps with variable speed drives are used to supply charging flow to the RCS. The speed of each pump can be controlled manually or automatically. During normal operation, only one charging pump is operating and the speed is modulated in accordance with pressurizer level.

APPLICABLE SAFETY ANALYSES

The LCO helps to ensure that sufficient seal water injection is provided to the RCPs. The HBRSEP, Unit No. 2 Individual Plant Examination (IPE), submitted to the NRC by letter dated August 31, 1992 (Ref. 2), found that the RCP seal injection function was a significant contributor to the overall core damage frequency. The plant event sequences of interest are a loss of all component cooling water which results in a loss of all charging capability and a loss of backup cooling to the RCP seals. The loss of all component cooling water is initiated by a loss of all AC power (station blackout), a multiple failure of component cooling, or a multiple failure resulting in loss of all service water cooling capability. Without either component cooling capability or charging flow to the RCP seals, the RCP seals fail resulting in a small break Loss-of-Coolant Accident (LOCA). The loss

(continued)

APPLICABLE SAFETY ANALYSES (continued)

of component cooling also results in a loss of cooling to the containment spray pumps and safety injection pumps. Hence, while the loss of seal injection capability is not the initiating event for the risk significant event sequences, the charging pumps perform a key function, which if lost, enables continuation of the risk significant event sequence to a state result of core damage.

The CVCS seal injection function satisfies Criterion 4 of the NRC Policy Statement.

LCO

In MODES 1, 2, 3, and 4, RCP seal injection is required to be OPERABLE to ensure that RCP seal integrity is maintained.

The CVCS is required to maintain minimum seal injection flow as measured by flow indication or by alternate means defined in procedures, to maintain a redundant charging capability to provide seal injection flow to the RCPs, and to maintain a redundant source of makeup water to the charging pumps.

Indication that RCP seal injection flow is within limits can be determined from indicated flow measurement to each RCP or by other means as described in procedures. RCP seal integrity is assured when seal injection flow meets surveillance requirements.

Two charging pumps powered from a normal power source are required to be OPERABLE. The emergency power supply sources are not required for the charging pumps to be OPERABLE. The charging pumps are also OPERABLE if they are powered from the emergency power source in lieu of the normal power source.

The CVCS is required to have a redundant means to provide a supply of makeup water to the charging pumps. Two supplies of makeup water are available from the RWST via a remotely operated air operated valve and locally operated manual valve. These sources provide both required Makeup Water Pathways from the RWST.

APPLICABILITY

In MODES 1, 2, 3, and 4, the CVCS OPERABILITY requirement for the risk significant function of injection to the RCP

(continued)

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BASES

APPLICABILITY (continued)

seals, is based upon full power operation. Although reduced power and MODES 3 and 4 conditions would result in less severe consequences of the risk significant sequences and a longer period of time would elapse before core damage occurs, the RCP seals must continue to be cooled in the lower MODES.

In MODES 5 and 6, plant conditions are such that the risk significance of loss of seal injection to the RCPs is significantly reduced. Therefore, CVCS OPERABILITY requirements in these MODES are not maintained in Technical Specifications.

ACTIONS

A.1

With one required charging pump inoperable, the inoperable pump must be returned to OPERABLE status within 24 hours. The 24 hour Completion Time is reasonable, based upon the original licensing basis.

B.1

With one Makeup Water Pathway inoperable, the inoperable components must be returned to OPERABLE status within 24 hours. The 24 hour Completion Time is consistent with the time permitted to restore an inoperable charging pump to OPERABLE status. Because there are two means of establishing Makeup Water Pathways, the remaining OPERABLE pathway will provide the required source of makeup water.

C.1 and C.2

If the inoperable components identified in Required Actions A.1 and B.1 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

(continued)

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.12 Low Temperature Overpressure Protection (LTOP) System

LCO 3.4.12 An LTOP System shall be OPERABLE with the accumulator isolation valves closed and deenergized and either a or b below:

a. 1. Two power operated relief valves (PORVs) with nominal lift settings of 400 psig and allowable values of ≤ 418 psig (PORVs with lift settings, found between CHANNEL CALIBRATIONS, greater than the nominal lift setting but less than the allowable value are OPERABLE);

2. A maximum of one Safety Injection (SI) pump capable of injecting into the RCS when all cold leg temperatures are ≥ 175°F; and

3. No SI pumps capable of injecting into the RCS when any cold leg temperature is < 175°F.

OR

b. The RCS depressurized and an RCS vent of ≥ 4.4 square inches.

APPLICABILITY: MODES 4 and 5,
MODE 6 when the reactor vessel head is on.

----------NOTE----------
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 Figures 3.4.3-1 and 3.4.3-2.

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.17 Chemical and Volume Control System (CVCS)

LCO 3.4.17 Reactor Coolant Pump (RCP) seal injection shall be OPERABLE, with:

a. Two charging pumps shall be OPERABLE; and

b. Two Makeup Water Pathways from the Refueling Water Storage Tank (RWST) shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required charging pump inoperable.	A.1 Restore required charging pump to OPERABLE status.	24 hours
B. One Makeup Water Pathway from the RWST inoperable.	B.1 Restore Makeup Water Pathway from the RWST to OPERABLE status.	24 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

(continued)

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.12 Low Temperature Overpressure Protection (LTOP) System

BASES

BACKGROUND

The LTOP System controls 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 maximum allowed PORV lift setting (allowable value) for LTOP is derived by analyses which model the performance of the LTOP System, assuming various mass input and heat input transients. Operation with a PORV lift setting less than or equal to the allowable value ensures that Reference 1 criteria will not be violated with consideration for a maximum pressure overshoot beyond the PORV lift setting which can occur as a result of time delays in signal processing and valve opening, instrument uncertainties, and single failure. The maximum allowed PORV lift setting (allowable value) for the LTOP is updated based on the results of examinations of reactor vessel material irradiation surveillance specimens performed as required by 10 CFR 50, Appendix H.

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; 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 P/T limits.

This LCO provides RCS overpressure protection by having a minimum coolant input capability and having adequate pressure relief capacity. Limiting coolant input capability

(continued)

BASES

BACKGROUND

PORV Requirements (continued)

temperature. The calculated pressure limit is then compared with the indicated RCS pressure from a wide range pressure channel. If the indicated pressure meets or exceeds the calculated value, a PORV is signaled to open.

The nominal lift setting is the nominal value at which the LTOP bistable is set. The bistable is considered to be properly adjusted (in accordance with the nominal lift setting) when the "as left" value is within the established calibration tolerance band. A PORV lift setting is required to be adjusted, if the lift setting is found outside the established calibration tolerance band, such that the lift setting is within the established tolerance band. The nominal lift setting and allowable value are based upon the analytical limit (i.e., the 10 CFR 50, Appendix G limit, less effects for dynamic head of operating Reactor Coolant Pumps (RCPs) and RHR pumps, static head due to location of pressure transmitters, and the pressure overshoot due to the mass and heat addition overpressure events). To account for the calibration tolerances and instrument drift, which are assumed to occur between calibrations, statistical allowances are provided in the lift setting. The OPERABILITY of each transmitter or sensor can be evaluated when its "as found" calibration data are compared against its documented acceptance criteria. The LCO specifies both the nominal lift setting and an allowable value for the setting that represents the maximum allowable "as found" value for the instrument to be considered OPERABLE during calibration. The actual nominal lift setting entered into the bistable is more conservative than that specified by the allowable value to account for changes in random measurement errors detectable by a Channel Operational Test (COT). One example of such a change in measurement error is drift during the surveillance interval. Channels with lift settings, found between CHANNEL CALIBRATIONS, not within the nominal lift setting but within the allowable value are OPERABLE. A detailed description of the methodology used to calculate the trip setpoints, including their explicit uncertainties, is provided in the CP&L setpoint methodology procedure (Ref. 11) which is based upon current Instrument Society of America (ISA) standards.

(continued)

BASES

BACKGROUND

PORV Requirements (continued)

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.

(continued)

BASES (continued)

LCO

This LCO requires that the LTOP System be OPERABLE. The LTOP System 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 consistent with assumptions of the analysis when the RCS is not depressurized and RCS vent is not established, the LCO requires all accumulator discharge isolation valves closed and immobilized when accumulator pressure is greater than or equal to the maximum RCS pressure for the existing RCS cold leg temperature allowed in the LTOP analyses, no more than one SI pump be capable of injecting into the RCS with all RCS cold leg temperatures ≥ 175°F, and no SI pumps be capable of injecting into the RCS with any RCS cold leg temperature < 175°F.

The elements of the LCO that provide low temperature overpressure mitigation through pressure relief are:

a. Two OPERABLE PORVs; or

   A PORV is OPERABLE for LTOP when its block valve is open, its lift setpoint is within the limit required by the LTOP analyses and testing proves its ability to open at this setpoint, and motive power is available to the two valves and their control circuits.

b. A depressurized RCS and an RCS vent.

   An RCS vent is OPERABLE when open with an area of ≥ 4.4 square inches. When the RCS is depressurized and a 4.4 square inch RCS vent is established, the LCO restrictions regarding SI injection capability are not required to be met.

Each of these methods of overpressure prevention is capable of mitigating the limiting LTOP transient.

(continued)

BASES

REFERENCES (continued)

9. 10 CFR 50, Appendix K.

10. Generic Letter 90-06.

11. Attachment VIII to CPL's letter to NRC dated May 30, 1997, H. B. Robinson Steam Electric Plant, Unit No. 2 - Response to Request for Additional Information and Transmittal of Supplement 4 Regarding the Technical Specification Change Request to Convert to the Improved Standard Technical Specification.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.13.1 (continued)

The 72 hour Frequency during steady state operation is a reasonable interval to trend LEAKAGE and recognizes the importance of early leakage detection in the prevention of accidents.

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.

REFERENCES

1. UFSAR, Section 3.1.

2. UFSAR, Chapter 15.

BASES

BACKGROUND (continued)

Makeup water to the RCS is provided by the CVCS from the following sources:

a. The primary water storage tank, in combination with boric acid storage tanks provides water for makeup and RCS boron concentration adjustments, and

b The Refueling Water Storage Tank (RWST) which, via one of two pathways, supplies borated water for emergency makeup.

Three positive displacement charging pumps with variable speed drives are used to supply charging flow to the RCS. The speed of each pump can be controlled manually or automatically. During normal operation, only one charging pump is operating and the speed is modulated in accordance with pressurizer level.

APPLICABLE SAFETY ANALYSES

The LCO helps to ensure that sufficient seal water injection is provided to the RCPs. The HBRSEP, Unit No. 2 Individual Plant Examination (IPE), submitted to the NRC by letter dated August 31, 1992 (Ref. 2), found that the RCP seal injection function was a significant contributor to the overall core damage frequency. The plant event sequences of interest are a loss of all component cooling water which results in a loss of all charging capability and a loss of backup cooling to the RCP seals. The loss of all component cooling water is initiated by a loss of all AC power (station blackout), a multiple failure of component cooling, or a multiple failure resulting in loss of all service water cooling capability. Without either component cooling capability or charging flow to the RCP seals, the RCP seals fail resulting in a small break Loss-of-Coolant Accident (LOCA). The loss of component cooling also results in a

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

loss of cooling to the containment spray pumps and safety injection pumps. Hence, while the loss of seal injection capability is not the initiating event for the risk significant event sequences, the charging pumps perform a key function, which if lost, enables continuation of the risk significant event sequence to a state result of core damage.

The CVCS seal injection function satisfies Criterion 4 of the NRC Policy Statement.

LCO

In MODES 1, 2, 3, and 4, RCP seal injection is required to be OPERABLE to ensure that RCP seal integrity is maintained.

The CVCS is required to maintain minimum seal injection flow as measured by flow indication or by alternate means defined in procedures, to maintain a redundant charging capability to provide seal injection flow to the RCPs, and to maintain a redundant source of makeup water to the charging pumps.

Indication that RCP seal injection flow is within limits can be determined from indicated flow measurement to each RCP or by other means as described in procedures. RCP seal integrity is assured when seal injection flow meets surveillance requirements.

Two charging pumps powered from a normal power source are required to be OPERABLE. The emergency power supply sources are not required for the charging pumps to be OPERABLE. The charging pumps are also OPERABLE if they are powered from the emergency power source in lieu of the normal power source.

The CVCS is required to have a redundant means to provide a supply of makeup water to the charging pumps. Two supplies of makeup water are available from the RWST via a remotely operated air operated valve and locally operated manual valve. These sources provide both required Makeup Water Pathways from the RWST.

APPLICABILITY

In MODES 1, 2, 3, and 4, the CVCS OPERABILITY requirement for the risk significant function of injection to the RCP

(continued)

BASES

APPLICABILITY (continued)

seals, is based upon full power operation. Although reduced power and MODES 3 and 4 conditions would result in less severe consequences of the risk significant sequences and a longer period of time would elapse before core damage occurs, the RCP seals must continue to be cooled in the lower MODES.

In MODES 5 and 6, plant conditions are such that the risk significance of loss of seal injection to the RCPs is significantly reduced. Therefore, CVCS OPERABILITY requirements in these MODES are not maintained in Technical Specifications.

ACTIONS

A.1

With one required charging pump inoperable, the inoperable pump must be returned to OPERABLE status within 24 hours. The 24 hour Completion Time is reasonable, based upon the original licensing basis.

B.1

With one Makeup Water Pathway inoperable, the inoperable components must be returned to OPERABLE status within 24 hours. The 24 hour Completion Time is consistent with the time permitted to restore an inoperable charging pump to OPERABLE status. Because there are two means of establishing Makeup Water Pathways, the remaining OPERABLE pathway will provide the required source of makeup water.

C.1 and C.2

If the inoperable components identified in Required Actions A.1 and B.1 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

(continued)

SUPPLEMENT 8
CONVERSION PACKAGE SECTION 3.5
PAGE INSERTION INSTRUCTIONS

Remove and insert the following pages into Enclosure 13 to Serial: RNP-RA/96-0141.

	Remove page	Insert Page
a.	Part 1, "Markup of Current Technical Specifications (CTS)"	
	NA	
b.	Part 2, "Discussion of Changes (DOCs) for CTS Markup"	
	6 through 9a	6a through 9
c.	Part 3, "No Significant Hazards Consideration (NSHC), And Basis for Categorical Exclusion from 10 CFR 51.22"	
	NA	
d.	Part 4, "Markup of NUREG-1431, Revision 1, Standard Technical Specifications Westinghouse Plants, (ISTS)"	
	3.5-4	3.5-4
	3.5-5	3.5-5
e.	Part 5, "Justification of Differences (JFDs) to ISTS"	
	4	4
f.	Part 6, "Markup of ISTS Bases"	
	B 3.5-18, B 3.5.18a, B 3.5-21	B 3.5-18, B 3.5.18a, B 3.5-21,
	B 3.5-22	B 3.5-22
g.	Part 7, "Justification for Differences (JFDs) to ISTS Bases"	
	4	4
h.	Part 8, "Proposed HBRSEP, Unit No. 2 ITS"	
	3.5-6	3.5-6
i.	Part 9, "Proposed Bases to HBRSEP, Unit No. 2 ITS"	
	B 3.5-17, B 3.5-21	B 3.5-17, B 3.5-21
j.	Part 10, "ISTS Generic Changes	
	NA	

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. With required action and associated completion time not met, ITS RA C.1 and C.2 requires achieving MODE 3 within 6 hours, and MODE 5 within 36 hours. 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. 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. This change is an additional restriction on plant operation and is consistent with NUREG-1431.

M19 A CTS surveillance requirement comparable to ITS SR 3.5.4.1 does not exist nor does CTS include limits on RWST temperature. ITS SR 3.5.4.1 requires periodic verification that the RWST is within specified temperature limits. The RWST borated water temperature is 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 is acceptable based on operating experience. ITS 3.5.4 Condition A with the associated Required Action and Completion time impose restrictions on operation with the RWST outside the specified limits. With RWST boron concentration or borated water temperature not within limits, 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 considers 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.

CTS 3.3.1.1.a specifies the requirements for RWST contained borated water volume but does not require a periodic verification. ITS SR 3.5.4.2 requires a verification of this parameter every 7 days. 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 and Containment Spray 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 is acceptable based upon operating experience. These changes are additional restrictions on plant operation and are consistent with NUREG-1431.

M20 CTS Table 4.1.2, Item 3 permits a maximum interval between test of 10 days. ITS SR 3.5.4.3 has a maximum interval of ≈ 9 days (7 days x 1.25). The ITS maximum SR interval is not a significant impact on plant operations and reflects a consistent approach to maximum

SR intervals. This change is an additional restriction on plant operation and is consistent with NUREG-1431.

M21 CTS does not currently place a requirement on the maximum boron concentration in the RWST. ITS SR 3.5.4.3 imposes an upper limit. The RWST upper limit 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. This change is an additional restriction on plant operation and is consistent with NUREG-1431.

M22 CTS 3.3.1.1.g requires that control power be removed from the specified valves at > 1000 psig. CTS 3.3.1.1.h requires that air be removed from the specified valves at > 1000 psig. ITS SR 3.5.2.1 and ITS SR 3.5.2.7 require motive power be removed from the valves in MODES 1, 2 and 3. Although not directly comparable, the CTS specified applicability of > 1000 psig normally occurs significantly above the MODE 3 lower temperature limits. Consistent with NUREG-1431 construction, SRs are generally applicable when the Specification is applicable. 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 in the lower MODES. The SI pump performance requirements are based on a small break LOCA. MODE 2 and MODE 3 requirements are bounded by the MODE 1 analysis. These changes are additional restrictions on plant operation and are consistent with NUREG-1431.

M23 CTS 3.3.1.1.e allows any one flow path including valves of the safety injection or residual heat removal system to be inoperable for up to 24 hours. ITS LCO 3.5.2 Applicability Note 1 permits, in MODE 3, one cold leg safety injection (SI) pump flow path to be isolated by closing the isolation valves for up to 24 hours to perform pressure isolation valve testing per SR 3.4.14.1. The restriction that only a cold leg injection flow path may be inoperable is a more restrictive requirement upon unit operation and has no adverse impact on safety. This more restrictive requirement is acceptable since only the cold leg safety injection pathways require isolation to perform SR 3.4.14.1, and other pathways (i.e., two (2)) are available for injection during the test.

TECHNICAL CHANGES - LESS RESTRICTIVE (GENERIC)

LA1 CTS 3.3.1.2.e explicitly excludes the SI hot leg pathways and valves from the requirements of the specification. This detail regarding applicability of the specification is relocated to the ITS bases.

The details associated with the involved Specifications are not required to be in the ITS to provide adequate protection of the public health and safety, since the ITS still retains the requirement for OPERABILITY of the ECCS. This approach provides an effective level of regulatory control and provides for a more appropriate change control process. The level of safety of facility operation is unaffected by the change because there is no change in the overall operational requirements. Furthermore, NRC and utility resources associated with processing license amendments to these requirements will be reduced. Therefore, relocation of these details is acceptable.

LA2 CTS 3.3.1.1 includes details regarding the equipment associated with OPERABLE ECCS trains. This requirement is relocated to the Bases for ITS 3.5.2 and ITS 3.5.3.

These details associated with the involved Specifications are not required to be in the ITS to provide adequate protection of the public health and safety, since the ITS still retains the requirement for OPERABILITY of the ECCS trains. This approach provides an effective level of regulatory control and provides for a more appropriate change control process. The level of safety of facility operation is unaffected by the change because there is no change in the overall operational requirements. Furthermore, NRC and utility resources associated with processing license amendments to these requirements will be reduced. Therefore, relocation of this information is acceptable.

TECHNICAL CHANGES - LESS RESTRICTIVE (SPECIFIC)

L1 During Power Operation CTS 3.3.1.2 permits one accumulator to be isolated or otherwise inoperable for up to four hours. ITS 3.5.1 RA A.1 permits one accumulator to be inoperable for boron concentration out of limits for 72 hours. Therefore, this is a less restrictive change and is consistent with NUREG-1431. The 72 hour Completion Time for restoration of the boron concentration to within limits is reasonable time to complete the Required Action including confirmatory sampling and analysis.

As stated in the bases, 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 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 demonstrates that the accumulators do not discharge following a large main steam line break.

The magnitude of a potential boron reduction is limited because of the SR 3.5.1.4 requirement to sample boron concentration after a volume addition of 10% of the indicated tank level that is not from the RWST. This ensures that a boron reduction below the lower limit is promptly identified and the magnitude of the change is limited.

L2 CTS 3.3.1.2 permits 24 hours to restore specified components/flowpaths to operable status or to be in hot shutdown. If components are not restored within an additional 48 hours, CTS 3.3.1.3 requires the unit be placed in Cold Shutdown. ITS 3.5.2 RA A.1 permits an ECCS train to be inoperable for 72 hours in MODES 1, 2 and 3 provided at least 100% of the ECCS flow equivalent to a single OPERABLE ECCS train is available. If the required actions or completion times of ITS 3.5.2 RA A.1 are not met, ITS 3.5.2 RA C.1 and RA C.2 require the unit to be in MODE 3 within 6 hours and MODE 4 within 12 hours respectively.

The allowance for more than one train to be inoperable, provided an equivalent 100% ECCS flow capability exists, as well as the increase in the allowable out of service time from 24 hours to 72 hours are less restrictive requirements upon unit operation. Additionally, ITS 3.5.2 RA C.1 and C.2 provide 6 hours to be in MODE 3 and 12 hours to be in MODE 4 respectively, in addition to the 72 hours allowable out of service time. Therefore, these are less restrictive changes and are consistent with NUREG-1431.

Due to the redundancy of trains and the diversity of subsystems, the inoperability of one component in a train does not render the ECCS incapable of performing its function. Neither does the inoperability of two different components, 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 a single OPERABLE ECCS train remains available. This allows increased flexibility in plant operations under circumstances when components in different trains are inoperable. The 72 hour Completion Time is based on an NRC reliability evaluation and is a reasonable time for repair of many ECCS components.

L3 CTS 4.5.1.1 requires the Safety Injection System tests be performed in such a manner to prevent injection into the reactor coolant system. This requirement is not retained in ITS. Although it is expected future testing will be consistent with current methodology which does not result in actual injection, testing which results in actual injection is acceptable since the test would still demonstrate acceptable system operation. Therefore, this is a less restrictive change and is consistent with NUREG-1431.

L4 CTS 4.5.1.2 specifies certain details regarding test method (e.g., control board indications and visual observation, proper sequence and timing, etc.) regarding acceptable Safety Injection System test results. These test method details are not retained in ITS. The ITS specified verification of pump starts and valve actuations is sufficient to demonstrate OPERABILITY. This change allows increased flexibility in testing methodology while still requiring verification of OPERABILITY. Therefore, this is a less restrictive change and is consistent with NUREG-1431.

L5 CTS 4.5.2.1 mandates a test method for the verification of the specified valve positions. Specifically, this specification requires verification ". . . from the RTGB indicators/controls . . ." that the specified valves are in the proper position with control power removed. This test method detail is not retained in ITS. The ITS specified verification that the valves are in their proper position with control power removed is sufficient to demonstrate OPERABILITY. This change allows increased flexibility in testing methodology while still requiring verification of OPERABILITY. Therefore, this is a less restrictive change and is consistent with NUREG-1431.

L6 In Hot Shutdown, CTS 3.3.1.3 imposes requirements for ECCS in accordance with CTS 3.3.1.1 and 3.3.1.2. CTS 3.3.1.1 requires two ECCS trains to be operable. CTS 3.3.1.2 permits one ECCS component (SI pump, RHR pump, RHR heat exchanger) to be inoperable for up to 24 hours. With less than one ECCS train OPERABLE, no specific action is provided. In this condition, entry into CTS 3.0 is required. CTS 3.0 requires the unit be placed in Cold Shutdown within 30 hours. ITS 3.5.3 requires only one ECCS train to be OPERABLE in MODE 4. With the required ECCS RHR subsystem inoperable, ITS 3.5.3 RA A.1 requires action be initiated immediately to restore one required ECCS RHR subsystem, to OPERABLE status. Therefore, this is a less restrictive change and is consistent with NUREG-1431.

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. 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.

L7 With the RWST boron concentration not within limits, CTS required action is specified in 3.0. CTS 3.0 requires achieving hot shutdown within 8 hours, followed by cold shutdown within an additional 30 hours. ITS 3.5.4 RA A.1 permits 8 hours to restore the RWST to OPERABLE status. With required action and associated completion time not met, ITS RA C.1 and C.2 requires achieving MODE 3 within 6 hours, and MODE 5 within 36 hours. Therefore, this aspect of the change is less restrictive change and is consistent with NUREG-1431.

The 8 hours to restore the boron concentration to within limits is acceptable based upon consideration of the time required to change the boron concentration and the fact that the contents of the tank are still available for injection. Permitting prompt corrective action to restore the boron concentration to within limits is preferable to requiring immediate plant shutdown, with its increased risk for shutdown transients.

L8 A CTS provision comparable to Note 2 to Applicability to ITS Specification 3.5.2 does not exist. This Note permits one ECCS train to be inoperable for up to four hours after entry into MODE 3 or until the RCS cold leg temperatures exceed 375°F, whichever comes first. Operation in MODE 3 with ECCS trains declared inoperable 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 rendered inoperable 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. This Note permits entry into MODE 3 without first meeting the LCO requirements. The limitations imposed on duration and cold leg temperatures are bounded by the 72 hours permitted by ITS 3.5.2 RA A.1 for one ECCS train being inoperable when in MODES 1, 2 and 3. Therefore, this is a less restrictive change on plant operation and is consistent with NUREG-1431.

TECHNICAL CHANGES - RELOCATED SPECIFICATIONS

None

CTS

3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

3.5.2 ECCS – Operating

[3.3.1.1.c,d,e,f]

LCO 3.5.2 Two ECCS trains shall be OPERABLE.

[3.3.1.1]

APPLICABILITY: MODES 1, 2, and 3.

4 24 one cold leg

NOTES

1. In MODE 3, both safety injection (SI) pump 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.

1 one required SI

2. Operation in MODE 3 with ECCS pumps declared inoperable pursuant to LCO 3.4.12, "Low Temperature Overpressure Protection (LTOP) System," is allowed for up to 4 hours or until the temperature of all RCS cold legs exceeds ~~375~~ °F, whichever comes first.

[L8]

[3.3.1.2 f]

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
[3.3.1.2.b] A. One or more trains inoperable. [3.3.1.2 c] AND At least 100% of the ECCS flow equivalent to a single OPERABLE ECCS train available.	A.1 Restore train(s) to OPERABLE status.	72 hours
[3.3.1.2] B C Required Action and associated Completion Time not met.	C.1 Be in MODE 3. AND C.2 Be in MODE 4.	6 hours 12 hours

20 INSERT 3.5.2-1a

Supplement 8

CTS

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.2.1 [4.5.2.1] [3.3.1.1.g]	Verify the following valves are in the listed position with power to the valve operator removed. (Control) (5) Number / Position / Function SI 862A & B [ ] [OPEN] [ ] SI 863A & B [ ] [CLOSED] [LHSI] SI 864A & B OPEN LHSI, SI 866A & B CLOSED HHSI SI 878A & B [ ] [OPEN] [HHSI]	12 hours (Low Head Safety Injection (LHSI)) (HIGH HEAD Safety Injection (HHSI))
SR 3.5.2.2 [4.5.2.2]	Verify 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 ECCS piping is full of water.~~	~~31 days~~ (17)
SR 3.5.2.~~4~~ (3) [A6]	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.~~5~~ (4) [4.5.1.1]	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.	~~[18]~~ months

(continued)

and valves are shared by both ECCS trains. Since the specified valves affect both trains, the provisions afforded by the ITS Actions for a single train are not applicable. Therefore the provisions afforded by Condition B are added to retain the CLB which permits restoring power or air to one valve among the SRs listed for maintenance or testing.

Since only one of the specified valves is permitted to have air or power restored, the Required Actions in Condition B are structured consistently with Required Actions B.1 and B.2 of LCO 3.5.1.

21 Not used.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.2.2 (continued)

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.

8

~~SR 3.5.2.3~~

~~With the exception of the operating centrifugal charging pump, the ECCS pumps are normally in a standby, nonoperating mode. As such, flow path piping has the potential to develop voids and pockets of entrained gases. Maintaining the piping from the ECCS pumps to the RCS full of water ensures that the system will perform properly, injecting its full capacity into the RCS upon demand. This will also prevent water hammer, pump cavitation, and pumping of noncondensible gas (e.g., air, nitrogen, or hydrogen) into the reactor vessel following an SI signal or during shutdown cooling. The 31 day Frequency takes into consideration the gradual nature of gas accumulation in the ECCS piping and the procedural controls governing system operation.~~

SR 3.5.2.~~4~~ 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.

35

Insert
B 3.5.2-7

SR 3.5.2.~~5~~ 4 and SR 3.5.2.~~6~~ 5

These Surveillances demonstrate that each automatic ECCS valve actuates to the required position on an actual or

(continued)

Supplement 8

Insert B 3.5.2-7

This ensures that pump performance is consistent with the pump curve.

1

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.

11

In MODE 4, the required ECCS train consists of ~~two separate~~ one high head safety injection (SI) subsystem~~s: centrifugal charging (high head) and~~ residual heat removal (RHR) (low head). 17

The ECCS flow paths consist of piping, valves, heat exchangers, and pumps such that water from the refueling water storage tank (RWST) 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.

18

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 certain automatic safety injection (SI) actuation ~~is~~ signals are not available. In this MODE, sufficient time exists for manual actuation of the required ECCS components to mitigate the consequences of a DBA.

restoration and

21

Only one train of ECCS is 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 the NRC Policy Statement.

17

LCO

In MODE 4, one of the two ~~independent (and~~ redundant~~)~~ ECCS trains is required to be OPERABLE to ensure that sufficient ECCS flow is available to the core following a DBA.

In MODE 4, an ECCS train consists of a ~~centrifugal charging~~ safety injection subsystem and an RHR subsystem. ~~Each train includes the piping, instruments, and controls to ensure an OPERABLE flow~~ 11

aligned either for shutdown cooling or for ECCS Mode

(continued)

Supplement 8

An ECCS train is OPERABLE when the train consists of piping instruments and controls to ensure an OPERABLE Flow.

The RHR Subsystem is OPERABLE when the pump meets its ISF Program requirements.

BASES

LCO (continued)

The hot leg injection paths of the SI System, including valves, are not subject to the requirements of this specification

path capable of taking suction from the RWST to the SI Pumps and transferring suction to the containment sump.

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 ECCS pumps and their respective supply headers to each of the ~~four~~ three cold leg injection nozzles. In the long term, this flow path may be switched to take its supply from the containment sump and to deliver its flow to the RCS hot and cold legs.

APPLICABILITY

Manual Alignment of the RHR subsystem would be necessary.

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 train 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.~~8~~4, "Residual Heat Removal (RHR) and Coolant Circulation – High Water Level," and LCO 3.9.~~6~~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

(continued)

pathways are required to be closed with control power removed. In this configuration, they are not OPERABLE. Manual operator action is required to restore control power and operate the valves.

35 The bases to ISTS SR 3.5.2.4 states that testing may be accomplished by measuring the pump developed head at only one point of the pump characteristic curve. The method normally utilized in the reference ISTS plant is to set the flow and measure the pump developed head. At HBRSEP, Unit No. 2,, no capability exists in MODES 1, 2, 3, or 4 to set the pump flow at a flow rate substantial enough to permit measurement of the developed head as a variable, The ASME Boiler & Pressure Vessel (B&PV) Code allows alternately to set the head and measure flow to determine measured pump performance to within an acceptable tolerance. This test method employed is at HBRSEP, Unit No. 2 in accordance with the Inservice Testing Program.

36 The bases are modified to describe operability consistent with the surveillance requirement for the specification. The RHR system is required to be manually aligned from shutdown cooling to the ECCS mode when required for the ECCS function in MODE 4.

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
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.	18 months
SR 3.5.2.5	Verify each ECCS pump starts automatically on an actual or simulated actuation signal.	18 months
SR 3.5.2.6	Verify, by visual inspection, the ECCS train containment sump suction inlet is not restricted by debris and the suction inlet trash racks and screens show no evidence of structural distress or abnormal corrosion.	18 months

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

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 reposition within the proper stroke time. This Surveillance does not require anytesting 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. This ensures that pump performance is consistent with the pump curve. SRs are specified in the Inservice Testing Program, which encompasses Section XI of the ASME Code. Section XI of the 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

(continued)

BASES

LCO (continued)

In MODE 4, an ECCS train consists of a safety injection subsystem and an RHR subsystem aligned either for shutdown cooling or for ECCS mode. An ECCS train is OPERABLE when the train consists of piping, instruments and controls to ensure an OPERABLE flow path capable of taking suction from the RWST to the SI pumps and transferring suction to the containment sump. The RHR subsystem is OPERABLE when the pump meets its IST program requirements.

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 ECCS pumps and their respective supply headers to each of the three cold leg injection nozzles. Manual alignment of the RHR subsystem would be necessary. In the long term, this flow path may be switched to take its supply from the containment sump and to deliver its flow to the RCS hot and cold legs. The hot leg injection paths of the SI System, including valves, are not subject to the requirements of this specification.

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 train 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."

(continued)

SUPPLEMENT 8
CONVERSION PACKAGE SECTION 3.6
PAGE INSERTION INSTRUCTIONS

Remove and insert the following pages into Enclosure 14 to Serial: RNP-RA/96-0141.

	Remove Page	Insert Page
a.	Part 1, "Markup of Current Technical Specifications (CTS)"	
	NA	
b.	Part 2, "Discussion of Changes (DOCs) for CTS Markup"	
	NA	
c.	Part 3, "No Significant Hazards Consideration (NSHC), And Basis for Categorical Exclusion form 10 CFR 51.22"	
	NA	
d.	Part 4, "Markup of NUREG-1431, Revision 1 Standard Technical Specifications Westinghouse Plants, (ISTS)"	
	3.6-12	3.6-12
e.	Part 5, "Justification of Differences (JFDs) to ISTS"	
	NA	
f.	Part 6, "Markup of ISTS Bases"	
	B 3.6-30, B 3.6-33, B 3.6-39	B 3.6-30, B 3.6-33, B 3.6-39
g.	Part 7, "Justification for Differences (JFDs) to ISTS Bases"	
	5	5
h.	Part 8, "Proposed HBRSEP, Unit No. 2 ITS"	
	3.6-2, 3.6-10, 3.6-11, 3.6-17	3.6-2, 3.6-10, 3.6-11, 3.6-17
i.	Part 9, "Proposed Bases to HBRSEP, Unit No. 2 ITS"	
	B 3.6-4, B 3.6-5, B 3.6-11, B 3.6-12	B 3.6-4, B 3.6-5, B 3.6-11, B 3.6-12
	B 3.6-21	B 3.6-21
	-	B 3.6-21a
	B 3.6-22	B 3.6-22
j.	Part 10, "ISTS Generic Changes"	
	NA	

CTS

E

5

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
Insert 3.6.3-2		25
~~SR 3.6.3.1~~	~~Verify each [42] inch purge valve is sealed closed, except for one purge valve in a penetration flow path while in Condition E of this LCO.~~	~~31 days~~ 21
[3.6.4.1] SR 3.6.3.2	1 Verify each 42 [8] inch supply + exhaust purge valve is closed, except when the [8] inch containment purge valves are open for pressure control, ALARA or air quality considerations for personnel entry, or for Surveillances that require the valves to be open. (safety related reasons) (tests or)	31 days + each 6 inch pressure + vacuum relief valve 5
[M13] SR 3.6.3.3 2	----------NOTES---------- 1. Valves and blind flanges in high radiation areas may be verified by use of administrative controls. ----------	29
[M13]	Verify each containment isolation manual valve and blind flange that is located outside containment and required to be closed during accident conditions is closed, except for containment isolation valves that are open under administrative controls.	31 days

(continued)

and not locked, sealed or otherwise secured 16

For containment isolation manual valves (except Penetration Pressurization System Valves with a diameter ≤ 3/8 inch) and blind flanges AND WOG STS 18 months for Penetration Pressurization System Valves with a diameter ≤ 3/8 inch 29

Insert B3.6.3-1 (5)

(1)

BASES

BACKGROUND (continued) - 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)

(11)

Shutdown Purge System (*42* inch purge valves)

personnel exposure to airborne radioactive contaminents

The Shutdown Purge System 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 [42] inch purge valves in some units are not qualified for automatic closure from their open position under DBA conditions. Therefore, the *42* inch purge valves are normally maintained closed in MODES 1, 2, 3, and 4 to ensure the containment boundary is maintained.

Insert B3.6.3-2

(12)

(12)

Insert B3.6.3-3

Insert B3.6.3-4

(13)

Minipurge System ([8] inch purge valves)

The Minipurge System 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 Minipurge 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.

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.

(continued)

Supplement 8

BASES (continued)

ACTIONS

The ACTIONS are modified by a Note allowing penetration flow paths, ~~[except for [42] 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 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 directly from the containment atmosphere to the environment, the penetration flow path containing these valves may not be opened under administrative controls. A single purge valve in a penetration flow path may be opened to effect repairs to an inoperable valve, as allowed by SR 3.6.3.1.~~ 12 12

A second Note 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 a third Note, which ensures appropriate remedial actions are taken, if necessary, if the affected systems are rendered inoperable by an inoperable containment isolation valve. 20

In the event the ~~air lock~~ 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.

A.1 and A.2

In the event one containment isolation valve in one or more penetration flow paths is inoperable ~~[except for purge valve or shield building bypass leakage not within limit]~~, 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 adversely affected by a single active

(continued)

Supplement 8

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.6.3.1

Each [42] inch containment purge valve 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. A containment purge valve that is sealed closed must have motive power to the valve operator removed. This can be accomplished by de-energizing the source of electric power or by removing the air supply to the valve operator. In this application, the term "sealed" has no connotation of leak tightness. The Frequency is a result of an NRC initiative, Generic Issue B-24 (Ref. 4), related to containment purge valve use during plant operations. In the event purge valve leakage requires entry into Condition E, the Surveillance permits opening one purge valve in a penetration flow path to perform repairs.

SR 3.6.3.2

This SR ensures that the purge valves are closed as required or, if open, open for an allowable reason. If a 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 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 valves are capable of closing in the environment following a LOCA. 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.

Safety related considerations (equipment or personnel) to support plant operations and maintenance activities within containment. Examples of this may include opening valves to reduce airborne activity to increase stay time, eliminate the need for respiratory protective equipment, reduce ambient temperatures during hot months, to increase the effectiveness of workers and to minimize the occupational effects of necessary, non-routine activities in containment.

Since it is not operationally necessary, it is desirable to preclude the 42 inch valves & 6 inch valves from being open at the same time. A Note to this SR restricts the 6 inch & 42 inch valves from being open simultaneously.

(continued)

developed head. At HBRSEP, Unit No. 2, no capability exists in MODES 1, 2, 3, or 4 to set the pump flow at a flow rate substantial enough to permit measurement of the developed head as a variable. The ASME Boiler & Pressure Vessel (B&PV) Code allows alternately to set the head and measure flow to determine measured pump performance to within an acceptable tolerance. This is the test method employed at HBRSEP, Unit No. 2 during the applicable MODES for ECCS. Therefore, the Bases to ITS SR 3.6.6.4 includes the plant's testing method allowed by the ASME B&PV Code.

53 The Bases is revised to state "volumetric average" in lieu of "average." The use of a volumetric average is consistent with the remainder of the Bases description and the methodology in use at HBRSEP, Unit No. 2.

54 The Bases for ITS SR 3.6.3.1 are revised to be consistent with the current licensing basis for the 42 inch purge supply and exhaust valves and the 6 inch pressure and vacuum relief valves. These valves may be opened for safety related reasons including operational testing and surveillances as reflected in the CTS Bases. This requirement was incorporated into the CTS by Amendment 99 dated July 3, 1986.

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.1.1	Perform required Type B and C leakage rate testing except for containment air lock testing, in accordance with 10 CFR 50, Appendix J, Option A, as modified by approved exemptions.	-----NOTE----- SR 3.0.2 is not applicable ----------
	The leakage rate acceptance criterion is ≤ 1.0 L_a. However, during the first unit startup following testing performed in accordance with 10 CFR 50, Appendix J, Option A, as modified by approved exemptions, the leakage rate acceptance criterion is < 0.6 L_a for the Type B and Type C tests.	In accordance with 10 CFR 50, Appendix J, Option A, as modified by approved exemptions
SR 3.6.1.2	Verify containment structural integrity in accordance with the Containment Tendon Surveillance Program.	In accordance with the Containment Tendon Surveillance Program
SR 3.6.1.3	Perform required visual examinations and Type A leakage rate testing, in accordance with the Containment Leakage Rate Testing Program.	In accordance with the Containment Leakage Rate Testing Program

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Required Action and associated Completion Time not met. OR 42 inch penetration (Supply or Exhaust) purge valves open and 6 inch penetration (pressure or vacuum relief) valves open simultaneously.	D.1 Be in MODE 3. AND D.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.3.1	----------NOTE---------- The 42 inch and 6 inch valves may not be open simultaneously. ---------- Verify each 42 inch purge supply and exhaust valve and each 6 inch pressure and vacuum relief valve is closed, except when the valves are open for safety related reasons, or for tests or Surveillances that require the valves to be open.	31 days

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.6.3.2	----------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 for containment isolation manual valves (except Penetration Pressurization System valves with a diameter ≤ 3/8 inch) and blind flanges AND 18 months for Penetration Pressurization System valves with a diameter ≤ 3/8 inch
SR 3.6.3.3	----------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)

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. AND At least 100% of the Spray Additive System flow equivalent to a single OPERABLE Spray Additive System train available to an OPERABLE Containment Spray Train.	A.1 Restore Spray Additive System train to OPERABLE status.	72 hours
B. Spray Additive System inoperable for reasons other than Condition A.	B.1 Restore Spray Additive System 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 84 hours

BASES

ACTIONS (continued)

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 leakage rate test requirements of 10 CFR 50, Appendix J (Ref. 1), Option A, as modified by approved exemptions. Air lock leakage is not acceptable if its contribution to overall Type B, and C leakage causes overall Type B and C leakage to exceed limits. As left leakage 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. At all other times between required leakage rate tests, the acceptance criteria is based on an overall leakage limit of $\leq 1.0\ L_a$. At $\leq 1.0\ L_a$ the offsite dose consequences are bounded by the assumptions of the safety analysis. SR Frequencies are as required by Appendix J, Option A. Thus, SR 3.0.2 (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.

SR 3.6.1.2

This SR ensures that the structural integrity of the containment will be maintained in accordance with the provisions of the Containment Tendon Surveillance Program.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3

Maintaining the containment OPERABLE requires compliance with the visual examinations and leakage rate test requirements of the Containment Leakage Rate Testing Program applicable to Type A leakage rate tests. Air lock leakage is not acceptable if its contribution to overall Type A leakage causes overall Type A leakage to exceed limits. As left leakage after performing a required 10 CFR 50, Appendix J, leakage test is required to be < 0.75 L_a for overall Type A leakage. 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. This periodic testing requirement verifies that the containment leakage rate does not exceed the leakage rate assumed in the safety analysis.

REFERENCES

1. 10 CFR 50, Appendix J.

2. UFSAR, Section 6.2.

BASES

ACTIONS

C.1, C.2, and C.3 (continued)

inoperable air lock to OPERABLE status, assuming that at least one door is maintained closed in the 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 the containment air lock OPERABLE requires compliance with the leakage rate test requirements of 10 CFR 50, Appendix J (Ref. 1), Option A, as modified by approved exemptions. This SR reflects the leakage rate testing requirements with regard to air lock leakage (Type B leakage tests). 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 Appendix J (Ref. 1), Option A, as modified by approved exemptions. Thus, SR 3.0.2 (which allows Frequency extensions) does not apply.

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 of SR 3.6.1.1. This ensures that air lock leakage is properly accounted for in determining the overall containment leakage rate.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

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 (procedures require strict adherence to single door opening), 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 the conditions that apply during a plant outage, and the potential for loss of containment OPERABILITY if the surveillance were performed with the reactor at power. The 24 month Frequency for the interlock is justified based on generic operating experience. The 24 month Frequency is based on engineering judgment and is considered adequate given that the interlock is not challenged during the use of the interlock.

REFERENCES

1. 10 CFR 50, Appendix J.

2. UFSAR, Paragraph 6.9.2.

BASES

ACTIONS

C.1 and C.2 (continued)

in a closed system. In some instances penetration flow paths connected to closed systems contain more than one containment isolation valve. The inoperability of one of these valves does not render the containment penetration flow path inoperable if the remaining containment isolation valve(s) is operable and the closed system is intact.

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 or if the 42 inch penetration (supply or exhaust) purge valves are open and the 6 inch penetration (pressure or vacuum relief) valves are open simultaneously, 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

This SR ensures that the 42 inch purge supply and exhaust valves and 6 inch pressure and vacuum relief valves are closed as required or, if open, open for an allowable reason. If a 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 valves are open for

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.3.1 (continued)

safety related considerations (equipment or personnel) to support plant operations and maintenance activities within containment. Examples of this may include operating the valves to reduce activity to increase stay times, eliminate the need for respiratory protective equipment, reduce ambient temperatures during hot months, to increase the effectiveness of workers and to minimize occupational

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.3.1 (continued)

effects of necessary, non-routine activities in containment, or for Surveillances that require the valves to be open. The valves are capable of closing in the environment following a LOCA. 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. Since it is not operationally necessary, it is desirable to preclude the 42 inch valves and 6 inch valves from being open at the same time. A Note to this SR restricts the 6 inch and 42 inch valves from being open simultaneously.

SR 3.6.3.2

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 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 applicable to containment isolation valves (except Penetration Pressurization System valves with a diameter ≤ 3/8 inch) and blind flanges. The 18 month Frequency is applicable to Penetration Pressurization System valves with a diameter ≤ 3/8 inch. These Frequencies are based on engineering judgment and were chosen to provide added assurance of the correct positions. The 18 month Frequency for Penetration Pressurization System valves ≤ 3/8 inch in diameter is considered acceptable based on the low probability of these valves being mispositioned and the minimal consequences associated with mispositioning one of these valves. 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, since these were

(continued)

SUPPLEMENT 8
CONVERSION PACKAGE SECTION 3.7
PAGE INSERTION INSTRUCTIONS

Remove and insert the following pages into Enclosure 15 to Serial: RNP-RA/96-0141

	Remove Page	Insert Page
a.	Part 1, "Markup of Current Technical Specifications (CTS)"	
	NA	
b.	Part 2, "Discussion of Changes (DOCs) for CTS Markup"	
	21	21
c.	Part 3, "No Significant Hazards consideration (NSHC), And Basis for Categorical Exclusion from 10 CFR 51.22	
	NA	
d.	Part 4, "Markup of NUREG-1431, Revision 1, Standard Technical Specifications Westinghouse Plants, (ISTS)"	
	3.7-13	3.7-13
e.	Part 5, "Justification of Differences (JFDs) to ISTS"	
	5	5
f.	Part 6, "Markup of ISTS Bases"	
	B 3.7-29	B 3.7-29
g.	Part 7, "Justification of Differences (JFDs) to ISTS Bases"	
	10	10
h.	Part 8, "Proposed HBRSEP, Unit No. 2 ITS"	
	3.7-2	3.7-2
	3.7-5	3.7-5
	3.7-11	3.7-11
i.	Part 9, "Proposed Bases to HBRSEP, Unit No.2 ITS"	
	B 3.7-27, B 3.7-28	B 3.7-27, B 3.7-28
	B 3.7-64, B 3.7-65	B 3.7-64, B 3.7-65
j.	Part 10, "ISTS Generic Changes"	
	NA	

temperatures of up to 120 degrees F for short periods of time. Operators in the control room, which is continuously manned, are immediately aware of temperatures approaching this range and would take the necessary procedural actions to reduce the temperature. Having two redundant Control Room air conditioners powered from separate emergency diesels ensures this action can be accomplished. This approach provides an effective level of regulatory control and provides for a more appropriate change control process. The level of safety of facility operation is unaffected by the change because there is no change in the overall operational requirements. Furthermore, NRC and licensee resources associated with processing license amendments to these requirements will be reduced. Therefore, relocation of these details is acceptable.

LA4 CTS 5.4.3 includes detail regarding the applicable safety analysis and associated references. This type of detail is not retained in the ITS and is relocated to the UFSAR.

This information is not required to be in the ITS to provide adequate protection of the public health and safety because it does not provide necessary information to enhance the specification. This approach provides an effective level of regulatory control and provides for a more appropriate change control process. The level of safety of facility operation is unaffected by the change because there is no change in the overall operational requirements. Furthermore, NRC and licensee resources associated with processing license amendments to these requirements will be reduced. Therefore, relocation of these details is acceptable.

LA5 CTS 3.12 requires that after the strong motion recorder indicates the operating basis earthquake has been exceeded, the reactor be shutdown and remain shutdown until after completion of specified inspections and repairs. The requirements associated with this specification are not retained in the ITS and are relocated to licensee controlled documents.

The requirements associated with the involved Specifications are not required to be in the ITS to provide adequate protection of the public health and safety, because the ITS still retains appropriate requirements for OPERABILITY of the required plant systems structure and components. This approach provides an effective level of regulatory control and provides for a more appropriate change control process. The level of safety of facility operation is unaffected by the change because there is no change in the overall operational requirements. Furthermore, NRC and licensee resources associated with processing license amendments to these requirements will be reduced. Therefore, relocation of these requirements is acceptable.

CTS

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
[M13] SR 3.7.~~8~~ 4.1	Verify each AFW manual, power operated, and automatic valve in each water flow path, ~~[~~and in ~~both~~ the steam supply flow paths to the steam ~~turbine~~ driven pump, ~~]~~ that is not locked, sealed, or otherwise secured in position, is in the correct AFW position.	31 days
[Doc M38] SR 3.7.~~8~~ 4.2	~~[~~----------NOTE---------- Not required to be performed for the ~~turbine~~ Steam driven AFW pump until ~~[~~24 hours~~]~~ after ≥ ~~[~~1000~~]~~ 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.	[31] days on a STAGGERED TEST BASIS
[4.8.3] SR 3.7.~~8~~ 4.3	----------NOTE---------- Not applicable in MODE 4 when steam generator is ~~relied upon~~ being used 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.	~~[~~18~~]~~ months

(continued)

Supplement 8

of ISTS 3.7.13.1 is revised in ITS 3.7.11.1 to require the FBACS to be operated for ≥ 10 continuous hours with the heaters operating automatically. This change is necessary to reflect the HBRSEP Unit No. 2 design of the Fuel Building Air Cleanup System (the system consists of a single train) and the fact that the heaters cycle on and off automatically to control humidity.

30 Not used.

31 Changes to ISTS 3.7.1 (ITS 3.7.1), Main Steam Safety Valves (MSSVs), are proposed to address recent issues related to improper Bases assumptions and overpressurization scenarios with inperable MSSVs. The changes are necessary to address the following:

a. ISTS 3.7.1 and associated Bases for requiring a reduction in reactor power proportional to the relief capacity of the remaining OPERABLE MSSVs is incorrect. As described in Westinghouse letter NSAL-94-001, "Operation at Reduced Power Levels with Inoperable MSSVs," January 20, 1994, and NRC Information Notice 94-60, "Potential Overpressurization of Main Steam System," August 22, 1994, the required reduction in reactor power is not directly proportional to the reduction in MSSV relieving capacity due to the effects of certain reactor trips that occur at full power which may not occur at partial power conditions. ISTS 3.7.1 and the associated Bases are revised to employ the heat balance algorithm included in NSAL-94-001.

b. For operation at partial power levels with a positive Moderator Temperature Coefficient (MTC), changes are made to require a reduction in the Power Range Neutron Flux-High reactor trip setpoint in addition to a reduction in reactor power when the MTC is positive. This is necessary to limit the primary side heat generation that may occur during an RCS heatup event. With a positive MTC, a heatup of the coolant will result in a power increase which requires additional steam relieving capacity.

c. Changes are made to require a reduction in the Power Range Neutron

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.7.6.1

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.

SR 3.7.6.2

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 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. The [31] day Frequency on a STAGGERED TEST BASIS results in testing each pump once every 3 months, as required by Reference 2.

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.

(continued)

Supplement 8

the combined steam flow capacity of the OPERABLE MSSVs and the turbine may be insufficient in some cases to prevent overpressurization of the Main Steam System prior to reaching the reactor trip setpoint.

d. Changes are made to statements in the Bases that are misleading or inconsistent with safety analysis methods.

A generic change has been submitted for the above described changes.

65 The basic performance requirements of the Ultimate Heat Sink (UHS) have been revised from a 30 day supply to a 22 day supply for minimum inflow conditions based upon a revised calculation. The calculation was revised as a result of information provided by the Service Water Pump manufacturer indicating that the Net Positive Suction Head (NPSH) assumption for the pumps should reflect that the pumps do not have antivortex difusers installed on the pumps. The NPSH requirement on the level of Lake Robinson was therefore raised to 210.64 ft MSL.

Additionally, the bases were revised to reflect that administrative control on lifting of the tainter gates would not apply when flood control measures are necessary to protect the integrity of the dam.

66 The bases to UHS are modified to reflect that the plant has a manual switchover of Emergency Core Cooling System (ECCS) suction from the Refueling Water Storage Tank (RWST) to the recirculation phase. The time frame until recirculation is established is longer than the 20 minutes indicated in ISTS.

67 ISTS SR 3.7.5.2 requires verification that each AFW pump's developed head at the test flow point is greater than or equal to the required developed head. The method normally utilized in the reference ISTS plant is to set the flow and measure the pump developed head. At HBRSEP, Unit No. 2,, no capability exists in MODES 1, 2, 3, or 4 to set the pump flow at a flow rate substantial enough to permit measurement of the developed head as a variable, The ASME Boiler & Pressure Vessel (B&PV) Code allows alternately to set the head and measure flow to determine measured pump performance to within an acceptable tolerance. This test method employed is at HBRSEP, Unit No. 2 in accordance with the Inservice Testing Program.

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. One or more steam generators with two or more MSSVs inoperable. OR One or more steam generators with one MSSV inoperable and MTC positive at any power level.	B.1	Reduce THERMAL POWER to less than or equal to the Maximum Allowable % RTP specified in Table 3.7.1-1 for the number of OPERABLE MSSVs.	4 hours
	AND		
	B.2	---------NOTE-------- Only required in MODE 1 ---------- Reduce the Power Range Neutron Flux - High reactor trip setpoint to less than or equal to the Maximum Allowable % RTP specified in Table 3.7.1-1 for the number of OPERABLE MSSVs.	72 hours
C. Required Action and associated Completion Time not met. OR One or more steam generators with ≥ 3 MSSVs inoperable.	C.1	Be in MODE 3.	6 hours
	AND		
	C.2	Be in MODE 4.	12 hours

3.7 PLANT SYSTEMS

3.7.2 Main Steam Isolation Valves (MSIVs)

LCO 3.7.2 Three MSIVs shall be OPERABLE.

APPLICABILITY: MODE 1,
MODES 2 and 3 except when all MSIVs are closed.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One MSIV inoperable in MODE 1.	A.1 Restore MSIV to OPERABLE status.	24 hours
B. Required Action and associated Completion Time of Condition A not met.	B.1 Be in MODE 2.	6 hours
C. ---------NOTE--------- Separate Condition entry is allowed for each MSIV. ---------- One or more MSIVs inoperable in MODE 2 or 3.	C.1 Close MSIV. AND C.2 Verify MSIV is closed.	8 hours Once per 7 days

(continued)

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.4.1	Verify each AFW manual, power operated, and automatic valve in each water flow path, and in the steam supply flow path to the steam driven AFW pump, that is not locked, sealed, or otherwise secured in position, is in the correct position.	31 days
SR 3.7.4.2	----------NOTE---------- Not required to be performed for the steam driven AFW pump until 24 hours after ≥ 1000 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.	31 days on a STAGGERED TEST BASIS
SR 3.7.4.3	----------NOTE---------- Not applicable in MODE 4 when steam generator is being used 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.	18 months

(continued)

BASES

ACTIONS (continued)

F.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.

SURVEILLANCE REQUIREMENTS

SR 3.7.4.1

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.

SR 3.7.4.2

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 centrifugal pump performance required by Section XI of the ASME Code (Ref. 4) to monitor centrifugal pump performance. 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 indicating abnormal performance. This ensures that pump performance is consistent with the pump curve. Performance of inservice testing discussed in the ASME Code, Section XI (Ref. 2)

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.4.2 (continued)

(only required at 3 month intervals) satisfies this requirement. The 31 day Frequency on a STAGGERED TEST BASIS results in testing each pump once every 3 months, as required by Reference 2.

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.

SR 3.7.4.3

This SR verifies that AFW can be delivered to the appropriate steam generator in the event of any accident or transient that generates an AFW actuation signal, 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 18 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 18 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 when AFW is being used for heat removal. In MODE 4, the required AFW train is already aligned and operating.

SR 3.7.4.4

This SR verifies that the AFW pumps will start in the event of any accident or transient that generates an AFW actuation

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.7.11.1

The FBACS should be checked periodically to ensure that it functions properly. As the environmental and normal operating conditions on this system are not severe, testing once every month provides an adequate check on this system.

Monthly heater operation dries out any moisture accumulated in the charcoal from humidity in the ambient air. Systems with heaters must be operated for ≥ 10 continuous hours with the heaters operating in the automatic mode under humidistat control to maintain the relative humidity at the inlet of the charcoal bed ≤ 70%. The 31 day Frequency is based on the known reliability of the equipment.

SR 3.7.11.2

This SR verifies that the required FBACS testing is performed in accordance with the Ventilation Filter Testing Program (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 3.7.11.3

This SR verifies the integrity of the fuel building enclosure. The ability of the fuel building to maintain negative pressure with respect to potentially uncontaminated adjacent areas is periodically tested to verify proper function of the FBACS. The FBACS is designed to maintain a slight negative pressure in the fuel building, to prevent unfiltered LEAKAGE. The Frequency of 18 months is consistent with the guidance provided in NUREG-0800, Section 6.5.1 (Ref. 5).

REFERENCES

1. UFSAR, Section 6.5.1.

2. UFSAR, Section 9.4.5.

(continued)

BASES

REFERENCES (continued)

3. UFSAR, Section 15.7.4.

4. 10 CFR 100.

5. NUREG-0800, Section 6.5.1, Rev. 2, July 1981.

SUPPLEMENT 8
CONVERSION PACKAGE SECTION 3.8
PAGE INSERTION INSTRUCTIONS

Remove and insert the following pages into Enclosure 16 to Serial: RNP-RA/96-0141.

	Remove Page	Insert Page
a.	Part 1, "Markup of Current Technical Specifications (CTS)"	
	NA	
	Part 2, "Discussion of Changes (DOCs) for CTS Markup"	
	NA	
c.	Part 3, " No Significant Hazards Consideration (NSHC), And Basis for Categorical Exclusion from 10 CFR 51.22	
	NA	
d.	Part 4, "Markup of NUREG-4131, Revision 1, Standard Technical Specifications-Westinghouse Plants, (ISTS)"	
	3.8-34	3.8-34
	3.8-37	3.8-37
e.	Part 5, "Justification of Differences (JFDs) to ISTS"	
	NA	
f.	Part 6, "Markup of ISTS Bases"	
	3.8-60	3.8-60
g.	Part 7, "Justification for Differences (JFDs) to ISTS Bases"	
h.	5	5
i.	Part 8, "Proposed HBRSEP, Unit No. 2 ITS"	
	3.8-28, 3.8-31	3.8-28, 3.8-31
i.	Part 9. "Proposed Bases to HBRSEP, Unit No. 2 ITS Bases"	
	B 3.8-2	B 3.8-2
	-	B 3.8-2a
	B 3.8-6, B 3.8-17	B 3.8-6, B 3.8-17
	-	B 3.8-17a
	B 3.8-45, B 3.8-47, B 3.8-75	B 3.8-45, B 3.8-47, B 3.8-75
	Part 10. "ISTS Generic Changes"	
	NA	

CTS

AC Instrument Bus Sources

23

3.8 ELECTRICAL POWER SYSTEMS

3.8.7 ~~Inverters~~ - Operating

Following AC Instrument Bus Power Sources

[M16] LCO 3.8.7 The ~~required Train A and Train B inverters~~ shall be OPERABLE.

~~----------NOTE----------~~
~~[One/two] inverter[s] may be disconnected from [its/their] associated DC bus for ≤ 24 hours to perform an equalizing charge on [its/their] associated [common] battery, provided:~~

~~a. The associated AC vital bus(es) [is/are] energized from [its/their] [Class 1E constant voltage source transformers] [inverter using internal AC source]; and~~

~~b. All other AC vital buses are energized from their associated OPERABLE inverters.~~

~~----------~~

[M16]

a. Inverters A and B, and
b. Constant Voltage Transformers (CVT) 1 and 2.

23

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

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
[M16] A. One ~~required~~ ~~inverter~~ inoperable.	A.1 ---------NOTE-------- Enter applicable Conditions and Required Actions of LCO 3.8.9, "Distribution Systems - Operating" with any ~~vital~~ instrument bus de-energized. ----------	
[M16]	Restore ~~inverter~~ to OPERABLE status.	24 hours

AC Instrument Bus Power Source

23

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(continued)

CTS

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ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
[M17] A. (continued)	A.2.4 Initiate action to restore required ~~inverters~~ AC Instrument Bus Sources to OPERABLE status.	Immediately

44

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
[M17] SR 3.8.8.1 Verify correct ~~inverter~~ instrument voltage, ~~,~~ frequency, ~~,~~ and alignments to required AC ~~vital~~ buses.	7 days

[M17]

NOTE

Actual voltage and frequency measurement is not required for AC instrument buses supplied from CVTs.

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Supplement 8

1

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 ~~6~~ 6 (Ref. 1) and Chapter ~~5~~ 15 (Ref. 2), assume that Engineered Safety Feature systems are OPERABLE. The DC electrical power system provides normal and emergency DC electrical power for the diesel generators, emergency auxiliaries, 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 the NRC Policy Statement.

35

LCO

The DC electrical power subsystems, each subsystem consisting of ~~two~~ one batteries, ~~one~~ a battery charger ~~per battery~~, and the corresponding control equipment and

57

(continued)

Supplement 8

systems. Therefore to ensure accuracy as well as consistency with other ITS sections, the term "single active failure" is used.

53 Provided clarification that in MODES 5 and 6 the unit auxiliary transformer backfed through the unit main transformer can be used as part of the qualified offsite circuit. This is CLB for HBRSEP Unit No. 2. The use of back charged unit auxiliary transformer when unit is shutdown is described in UFSAR Sections 8.2 and 8.3. This capability was reviewed and approved by NRC by issuance of Amendment No. 88 dated 1/2/85.

54 The references are modified based upon either plant specific utilization in the associated Bases or specific applicability to the facility.

55 The minimum battery voltage output of 2.13 volts per cell and total output of 128 volts is not discussed in the UFSAR.

56 The bases to SR 3.8.4.1 are revised to reflect the voltage associated with a single battery cell jumpered out. This change is consistent with the current licensing basis which does not specify the battery float voltage requirement.

57 The Bases are modified to allow operability of the DC electrical power subsystems powered either from the battery charger or the batteries. In a loss of offsite power during MODES 5 and 6, manual loading of the battery charger to the diesel generator is sufficient to support required systems in these MODES.

58 The Bases description for ITS SR 3.8.4.6 is modified to indicate "average on previous performance test." This corrects the Bases text to be consistent with the applicable revision of IEEE-450.

3.8 ELECTRICAL POWER SYSTEMS

3.8.7 AC Instrument Bus Sources – Operating

LCO 3.8.7 The following AC Instrument Bus Power Sources shall be OPERABLE:

a. Inverters A and B, and
b. Constant Voltage Transformers (CVT) 1 and 2.

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

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One AC Instrument Bus power source inoperable.	A.1	---------NOTE-------- Enter applicable Conditions and Required Actions of LCO 3.8.9, "Distribution Systems - Operating" with any instrument bus de-energized. ----------	
		Restore AC Instrument Bus Power Source to OPERABLE status.	24 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

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.2.3 Initiate action to suspend operations involving positive reactivity additions.	Immediately
	AND	
	A.2.4 Initiate action to restore AC instrument bus sources to OPERABLE status.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.8.1	----------NOTE---------- Actual voltage and frequency measurement is not required for AC instrument buses supplied from CVTs. ----------	
	Verify correct inverter voltage, frequency, and alignments to required AC instrument buses.	7 days

BASES

BACKGROUND (continued)

the connecting straps. The main transformer backfeeding will only be done during MODES 5 or 6 unless nuclear safety considerations require it to be done during MODES 2 or 3 (in accordance with applicable Required Actions) when no other offsite power sources are available. A detailed description of the offsite power network and the circuits to the ESF buses is found in the UFSAR, Chapter 8 (Ref. 2).

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 ESF buses. This includes the circuit path from the 115kV switchyard up to and including the feeder breakers to ESF buses E1 and E2 via the startup transformer, 4,160 V buses 2 and 3, and station service transformer 2G and 2F.

Certain required unit loads are returned to service in a predetermined sequence in order to prevent overloading the transformer supplying offsite power to the onsite Distribution System. Within 1 minute after the initiating signal is received, all automatic and permanently connected loads needed to recover the unit or maintain it in a safe condition are returned to service via the load sequencer.

The onsite standby power source for each 480 V ESF bus is a dedicated emergency DG. DGs A and B are dedicated to ESF buses E1 and E2, respectively. A DG starts automatically on a safety injection (SI) signal (e.g., low pressurizer pressure or high containment pressure signals) or on an ESF bus degraded voltage or 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 or degraded voltage, 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 the automatic load sequencer. The sequencing logic controls the permissive and starting signals to motor breakers to prevent overloading the DG by automatic load application.

(continued)

BASES

BACKGROUND (continued)

In the event of the loss of preferred power, the ESF electrical loads are automatically connected to the DGs in sufficient time to provide for safe reactor shutdown and to

(continued)

BASES

ACTIONS

A.1 (continued)

upon the assumption that two complete safety trains are OPERABLE. When no offsite sources are OPERABLE, this assumption is not the case, and a shorter Completion Time of 12 hours is appropriate.

A.2

Operation may continue in Condition A for a period that should not exceed 24 hours. With the offsite circuit inoperable, the reliability of the AC power system is degraded, with attendant potential for a challenge to the unit safety systems. In this Condition, however, the remaining OPERABLE DGs are adequate to supply electrical power to the onsite Distribution System.

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.

The second Completion Time for Required Action A.1 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition A is entered while, for instance, a DG is inoperable and that DG is subsequently returned OPERABLE, the LCO may already have been not met for up to 7 days. This could lead to a total of 8 days, since initial failure to meet the LCO, to restore the offsite circuit. At this time, a DG could again become inoperable, the circuit restored OPERABLE, and an additional 7 days (for a total of 15 days) allowed prior to complete restoration of the LCO. The 8 day Completion Time provides a limit on the time allowed in a 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 the 24 hours and 8 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

The Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock."

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.9 (continued)

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 required to be stroked open, or high pressure injection systems are not capable of being operated at full flow, 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 systems 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 18 months takes into consideration unit conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

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 continuously circulated and temperature maintained consistent with manufacturer recommendations. The reason for Note 2 is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. Note 3 to this SR permits removal of the bypass for protective trips after the DG has properly assumed its loads on the bus. This reduces exposure of the DG to undue risk of damage that might render it inoperable.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.10

This Surveillance demonstrates that the DG automatically starts and achieves the required voltage and frequency within the specified time (10 seconds) from the design basis

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.4.6 (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.

REFERENCES

1. UFSAR Section 3.1.
2. UFSAR, Chapter 8.
3. UFSAR, Chapter 6.
4. UFSAR, Chapter 15.
5. IEEE-450-1980.

BASES (continued)

LCO

The DC electrical power subsystems, each subsystem consisting of one battery or a battery charger, and the corresponding control equipment and interconnecting cabling within the train, are required to be OPERABLE to support required 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).

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.

ACTIONS

A.1, A.2.1, A.2.2, A.2.3, and A.2.4

If two trains are required by LCO 3.8.10, the remaining train with 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

(continued)

BASES

ACTIONS (continued)

F.1 and F.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.

G.1

With two trains with inoperable distribution subsystems that result in a loss of safety function, adequate core cooling, containment OPERABILITY and other instrument functions for DBA mitigation would be compromised, and immediate plant shutdown in accordance with LCO 3.0.3 is required.

SURVEILLANCE REQUIREMENTS

SR 3.8.9.1

This Surveillance verifies that the required AC, DC, and AC 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 7 day Frequency takes into account the redundant capability of the AC, DC, and AC instrument bus electrical power distribution subsystems, and other indications available in the control room that alert the operator to subsystem malfunctions.

This SR is modified by a Note which states that Voltage measurement is not required for the AC Instrument buses supplied from Constant Voltage Transformers (CVTs). For these buses confirmation that the buses are energized by observing status lights, instrument displays, etc., is sufficient to confirm the buses are energized.

(continued)

SUPPLEMENT 8
CONVERSION PACKAGE SECTION 3.9
PAGE INSERTION INSTRUCTIONS

Remove and insert the following pages into Enclosure 17 to Serial: RNP-RA/96-0141.

	Remove Page	Insert Page
a.	Part 1, "Markup of Current Technical Specifications (CTS)"	
	NA	
b.	Part 2, "Discussion of Changes (DOCs) for CTS Markup"	
	6	6
c.	Part 3, " No Significant Hazards Consideration (NSHC), And Basis for Categorical Exclusion from 10 CFR 51.22	
	NA	
d.	Part 4, "Markup of NUREG-4131, Revision 1, Standard Technical Specifications-Westinghouse Plants, (ISTS)"	
	NA	
e.	Part 5, "Justification of Differences (JFDs) to ISTS"	
	NA	
f.	Part 6, "Markup of ISTS Bases"	
	B 3.9-1, B 3.9-2, B 3.9-3	B 3.9-1, B 3.9-2, B 3.9-3
g.	Part 7, "Justification for Differences (JFDs) to ISTS Bases"	
	NA	
h.	Part 8, "Proposed HBRSEP, Unit No. 2 ITS"	
	NA	
i.	Part 9. "Proposed Bases to HBRSEP, Unit No. 2 ITS Bases"	
	B 3.9-1, B 3.9-2, B 3.9-3	B 3.9-1, B 3.9-2, B 3.9-3
j.	Part 10. "ISTS Generic Changes"	
	NA	

3.9.6 has Applicability, "during movement of irradiated fuel assemblies within containment." 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. This change is appropriate since a fuel handling accident can also occur when handling irradiated fuel outside the reactor vessel. Since this change imposes new requirements, it is more restrictive and has no adverse impact on safety.

M12 The CTS is revised to adopt ITS SR 3.9.6.1, which requires verification every 12 hours that the refueling cavity water level is ≥ 23 feet above the top of the reactor vessel flange. 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. 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. Since no similar Specification exists, this change is more restrictive and has no adverse impact on safety.

M13 CTS Specification 3.8.1.d is revised to add a Required Action to suspend positive reactivity additions in the event only one source range neutron flux monitor is OPERABLE, and this requirement is retained in ITS as LCO 3.9.2 Required Action A.2. CTS Specification 3.8.1.j, which requires that "refueling of the reactor" shall cease if any of the specifications are not met, is modified to restate "refueling of the reactor" as CORE ALTERATIONS. The incorporation of these CTS requirements into ITS Required Actions A.1 and A.2 is more restrictive because the actions now apply unequivocally to a single source range neutron flux monitor inoperable, rather than one or both monitors inoperable. 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. This change has no adverse impact on safety.

M14 Not used.

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), the refueling canal, and the refueling cavity 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.

Core Operating Limits Report

0.9433

HBRSEP design criteria

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 through the open reactor vessel by gravity feeding or by the use of the Residual Heat Removal (RHR) System pumps.

Safety Injection (SI) System or

SI or

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

(continued)

Supplement 8

BASES

BACKGROUND (continued)

canal. The RHR System is in operation during refueling (see LCO 3.9.5, "Residual Heat Removal (RHR) and Coolant Circulation-High Water Level," and LCO 3.9.6, "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, the refueling canal, 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 pool, 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 B 3.1.8, "SHUTDOWN MARGIN (SDM)"

The RCS boron concentration satisfies Criterion 2 of the NRC Policy Statement.

LCO

The LCO requires that a minimum boron concentration be maintained in the RCS, the refueling canal, and the refueling cavity while in MODE 6. The boron concentration limit specified in the COLR ensures that a core k_{eff} of

(continued)

Supplement 8

BASES

LCO (continued) ≤ 0.95 (0.9433) 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} ≤ 0.95 (0.9433). Above MODE 6, LCO 3.1.1, "SHUTDOWN MARGIN (SDM) - T_{avg} > 200°F," and LCO 3.1.2, "SHUTDOWN MARGIN (SDM) - T_{avg} ≤ 200°F," ensure 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, the refueling canal, 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 concentration as soon as possible, the operator should begin boration with the best source available for unit conditions.

(continued)

Supplement 8

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), the refueling canal, and the refueling cavity 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 Core Operating Limits Report (COLR). Plant procedures ensure the specified boron concentration in order to maintain an overall core reactivity of $k_{eff} \leq 0.9433$ during fuel handling, with control rods and fuel assemblies assumed to be in the most adverse configuration (least negative reactivity) allowed by plant procedures.

HBRSEP design criteria 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 through the open reactor vessel by the use of the Safety Injection (SI) System or Residual Heat Removal (RHR) System pumps.

The pumping action of the SI or 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

(continued)

BASES

BACKGROUND (continued)

canal. The RHR System is in operation 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, the refueling canal, 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 ≤ 0.9433 during the refueling operation. Hence, at least a 6% $\Delta k/k$ margin of safety is established during refueling.

During refueling, the water volume in the spent fuel pool, 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 B 3.1.1, "SHUTDOWN MARGIN (SDM)."

The RCS boron concentration satisfies Criterion 2 of the NRC Policy Statement.

LCO

The LCO requires that a minimum boron concentration be maintained in the RCS, the refueling canal, and the refueling cavity while in MODE 6. The boron concentration limit specified in the COLR ensures that a core k_{eff} of

(continued)

BASES

LCO (continued)

≤ 0.9433 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 $k_{eff} \leq 0.9433$. Above MODE 6, LCO 3.1.1, "SHUTDOWN MARGIN (SDM)," ensure 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, the refueling canal, 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 concentration as soon as possible, the operator should begin boration with the best source available for unit conditions.

(continued)

A1

F. Physical Protection

The licensee shall fully implement and maintain in effect all provisions of the Commission-approved physical security, guard training and qualification, and safeguards contingency plans including amendments made pursuant to provisions of the Miscellaneous Amendments and Search Requirements revisions to 10 CFR 73.55 (51 FR 27817 and 27822) and to the authority of 10 CFR 50.90 and 10 CFR 50.54(p). The plans, which contain Safeguards Information protected under 10 CFR 73.21, are entitled: "H. B. Robinson Steam Electric Plant Industrial Security Plan," with revisions submitted through October 21, 1987; "H. B. Robinson Steam Electric Plant Security Personnel Training and Qualification Plan," with revisions submitted through January 16, 1987; and "H. B. Robinson Steam Electric Plant Safeguards Contingency Plan," with revisions submitted through March 27, 1986. Changes made in accordance with 10 CFR 73.55 shall be implemented in accordance with the schedule set forth therein.

NO CHANGE

G. The following programs shall be implemented and maintained by the licensee:

[5.5.10]

(1) A secondary water chemistry monitoring program to inhibit steam generator tube degradation. This program shall include: the identification of critical parameters, their sampling frequency, sampling points and control band limits; requirements for the documentation and review of sample results; the identification of the authority responsible for the interpretation of sample results; the procedures used to measure the critical parameters; and the procedures which identify the administrative events and corrective actions required to return the secondary chemistry to its normal control band following an out of control band condition.

(2) A program to reduce leakage from systems outside containment that would or could contain highly radioactive fluids during a serious transient or accident to as low as practical levels. This program shall include: provisions for preventive maintenance and periodic visual inspection requirements, and integrated leak test requirements for each system at a frequency not to exceed refueling cycle intervals.

See 5.5.2

No Change

(3) A program to determine the airborne iodine concentration in vital areas under accident conditions. This program shall include: training of personnel, procedures for monitoring, and provisions for maintenance of sampling and analysis equipment.

(4) A program to ensure the capability to obtain and analyze reactor coolant, radioactive iodines, and particulates in plant gaseous effluents, and containment atmosphere samples

See 5.5.3

Specification 5.5

(FOL DPR-23)

ITS

A1

F. Physical Protection

The licensee shall fully implement and maintain in effect all provisions of the Commission-approved physical security, guard training and qualification, and safeguards contingency plans including amendments made pursuant to provisions of the Miscellaneous Amendments and Search Requirements revisions to 10 CFR 73.55 (51 FR 27817 and 27822) and to the authority of 10 CFR 50.90 and 10 CFR 50.54(p). The plans, which contain Safeguards Information protected under 10 CFR 73.21, are entitled: "H. B. Robinson Steam Electric Plant Industrial Security Plan," with revisions submitted through October 21, 1987; "H. B. Robinson Steam Electric Plant Security Personnel Training and Qualification Plan," with revisions submitted through January 16, 1987; and "H. B. Robinson Steam Electric Plant Safeguards Contingency Plan," with revisions submitted through March 27, 1986. Changes made in accordance with 10 CFR 73.55 shall be implemented in accordance with the schedule set forth therein.

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See 5.5.10

(2) A program to reduce leakage from systems outside containment that would or could contain highly radioactive fluids during a serious transient or accident to as low as practical levels. This program shall include: provisions for preventive maintenance and periodic visual inspection requirements, and integrated leak test requirements for each system at a frequency not to exceed refueling cycle intervals.

See 5.5.2

No Change

(3) A program to determine the airborne iodine concentration in vital areas under accident conditions. This program shall include: training of personnel, procedures for monitoring, and provisions for maintenance of sampling and analysis equipment.

[5.5.3]

(4) A program to ensure the capability to obtain and analyze reactor coolant, radioactive iodines, and particulates in plant gaseous effluents, and containment atmosphere samples

ITS

F. Physical Protection

The licensee shall fully implement and maintain in effect all provisions of the Commission-approved physical security, guard training and qualification, and safeguards contingency plans including amendments made pursuant to provisions of the Miscellaneous Amendments and Search Requirements revisions to 10 CFR 73.55 (51 FR 27817 and 27822) and to the authority of 10 CFR 50.90 and 10 CFR 50.54(p). The plans, which contain Safeguards Information protected under 10 CFR 73.21, are entitled: "H. B. Robinson Steam Electric Plant Industrial Security Plan," with revisions submitted through October 21, 1987; "H. B. Robinson Steam Electric Plant Security Personnel Training and Qualification Plan," with revisions submitted through January 16, 1987; and "H. B. Robinson Steam Electric Plant Safeguards Contingency Plan," with revisions submitted through March 27, 1986. Changes made in accordance with 10 CFR 73.55 shall be implemented in accordance with the schedule set forth therein.

NO CHANGE

G. The following programs shall be implemented and maintained by the licensee:

(1) A secondary water chemistry monitoring program to inhibit steam generator tube degradation. This program shall include: the identification of critical parameters, their sampling frequency, sampling points and control band limits; requirements for the documentation and review of sample results; the identification of the authority responsible for the interpretation of sample results; the procedures used to measure the critical parameters; and the procedures which identify the administrative events and corrective actions required to return the secondary chemistry to its normal control band following an out of control band condition.

See 5.5.10

[5.5.2]

(2) A program to reduce leakage from systems outside containment that would or could contain highly radioactive fluids during a serious transient or accident to as low as practical levels. This program shall include: provisions for preventive maintenance and periodic visual inspection requirements, and integrated leak test requirements for each system at a frequency not to exceed refueling cycle intervals.

No CHANGE

(3) A program to determine the airborne iodine concentration in vital areas under accident conditions. This program shall include: training of personnel, procedures for monitoring, and provisions for maintenance of sampling and analysis equipment.

(4) A program to ensure the capability to obtain and analyze reactor coolant, radioactive iodines, and particulates in plant gaseous effluents, and containment atmosphere samples

See 5.5.3

The systems include RHR, SIS, CSS, Post Accident Containment Ventilation; and portions of CVCS, Liquid and gaseous waste Disposal, and Sampling.

M13

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 and modification to systems or equipment that affect nuclear safety.

5.1.2 The Superintendent-Shift Operations (SSO) shall be responsible for the control room command function. During any absence of the SSO 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 SSO 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.

SUPPLEMENT 8
CONVERSION PACKAGE SECTION 4.0
PAGE INSERTION INSTRUCTIONS

Remove and insert the following pages into Enclosure 18 to Serial: RNP-RA/96-0141.

	Remove Page	Insert Page
a.	Part 1, "Markup of Current Technical Specifications (CTS)"	
	NA	
b.	Part 2, "Discussion of Changes (DOCs) for CTS Markup"	
	NA	
c.	Part 3, "No Significant Hazards Consideration (NSHC), And Basis for Categorical Exclusion for 10 CFR 51.22"	
	NA	
d.	Part 4, "Markup of NUREG-4131, Revision 1, Standard Technical Specifications-Westinghouse Plants, (ISTS)"	
	NA	
e.	Part 5, "Justification of Differences (JFDs) to ISTS"	
	NA	
f.	Part 6, "Markup of ISTS Bases"	
	NA	
g.	Part 7, "Justification for Differences (JFDs) to ISTS Bases"	
	NA	
h.	Part 8, "Proposed HBRSEP, Unit No. 2 ITS"	
	4.0-2	4.0-2
i.	Part 9, "Proposed Bases to HBRSEP, Unit No. 2 ITS Bases"	
	NA	
J.	Part 10, "ISTS Generic Changes"	
	NA	

4.0 DESIGN FEATURES

4.3 Fuel Storage (continued)

b. $k_{eff} \leq 0.95$ if fully flooded with unborated water, which includes an allowance for uncertainties as described in Section 9.1 of the UFSAR;

c. A nominal 10.5 inch center-to-center distance between fuel assemblies placed in the high density fuel storage racks;

d. A nominal 21 inch center-to-center distance between fuel assemblies placed in low density fuel storage racks;

e. Fuel assemblies with maximum planar enrichments greater than 4.55 + 0.05 (4.55 nominal) weight percent U_{235} have requirements for minimum integral burnable absorber content.

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. $k_{eff} \leq 0.95$ if fully flooded with unborated water, which includes an allowance for uncertainties as described in Section 9.1 of the UFSAR;

c. $k_{eff} \leq 0.98$ in an optimum moderation event, which includes an allowance for uncertainties as described in Section 9.1 of the UFSAR; and

d. A nominal 21 inch center to center distance between fuel assemblies placed in the storage racks.

4.3.2 Drainage

The spent fuel storage pool is designed and shall be maintained to prevent inadvertent draining of the pool below 18 feet above the fuel.

4.3.3 Capacity

The spent fuel storage pool is designed and shall be maintained with a storage capacity limited to no more than 544 assemblies.

SUPPLEMENT 8
CONVERSION PACKAGE SECTION 5.0
PAGE INSERTION INSTRUCTIONS

Remove and insert the following pages into Enclosure 19 to Serial: RNP-RA/96-0141.

	Remove Page	Insert Page
a.	Part 1, "Markup of Current Technical Specifications (CTS)"	
	FOL p.4 (ITS 5.5.2)	FOL p.4 (ITS 5.5.2)
	FOL p.4 (ITS 5.5.3)	FOL p.4 (ITS 5.5.3)
	FOL p.4 (ITS 5.5.10)	FOL p.4 (ITS 5.5.10)
b.	Part 2, "Discussion of Changes (DOCs) for CTS Markup"	
	NA	
c.	Part 3, "No Significant Hazards Consideration (NSHC), And Basis for Categorical Exclusion form 10 CFR 51.22"	
	NA	
d.	Part 4, "Markup of NUREG-1431, Revision 1, Standard Technical Specifications Westinghouse plants, (ISTS)"	
	NA	
e.	Part 5, "Justification of differences (JFDs) to ISTS"	
	NA	
f.	Part 6, "Markup of ISTS Bases"	
	NA	
g.	Part 7, "Justification for Differences (JFDs) to ISTS Bases"	
	NA	
h.	Part 8, "Proposed HBRSEP, Unit No. 2 ITS"	
	5.0-1	5.0-1
i.	Part 9, "Proposed Bases to HBRSEP, Unit No. 2 ITS"	
	NA	
j.	Part 10, "ISTS Generic Changes"	
	NA	

SUPPLEMENT 8
CONVERSION PACKAGE COMPILATION OF CTS PAGES
PAGE INSERTION INSTRUCTIONS

Remove and insert the following pages into Enclosure 21 to Serial: RNP-RA/96-0141.

Remove Page	Insert Page
FOL p.4 (5.5.2)	FOL p.4 (5.5.2)
FOL p.4 (5.5.3)	FOL p.4 (5.5.2)
FOL p.4 (5.5.10)	FOL p.4 (5.5.10)
2.3-1 (3.3.1)	2.3-1 (3.3.1)
2.3-3 (3.3.1)	2.3-3 (3.3.1)
3.1-4 (3.4.12)	3.1-4 (3.4.12)
3.4-6 (3.3.8)	3.4-6 (3.3.8)
3.5-10 (3.3.2)	3.5-10 (3.3.2)
-	3.5-13 (3.1.4)
3.5-13b (3.3.1)	3.5-13b (3.3.1)
-	3.5-13c (3.1.4)
3.5-15a (sheet 2) (3.3.5)	3.5.15a (sheet 2) (3.3.5)
3.5-19a (3.3.3)	3.5-19a (3.3.3)
4.1-7 (3.3.1)	4.1-7 (3.3.1)
4.1-9 (3.3.1)	4.1-9 (3.3.1)
4.1-12 (3.1.4)	4.1-12 (3.1.4)

A1

F. Physical Protection

NO CHANGE

The licensee shall fully implement and maintain in effect all provisions of the Commission-approved physical security, guard training and qualification, and safeguards contingency plans including amendments made pursuant to provisions of the Miscellaneous Amendments and Search Requirements revisions to 10 CFR 73.55 (51 FR 27817 and 27822) and to the authority of 10 CFR 50.90 and 10 CFR 50.54(p). The plans, which contain Safeguards Information protected under 10 CFR 73.21, are entitled: "H. B. Robinson Steam Electric Plant Industrial Security Plan," with revisions submitted through October 21, 1987; "H. B. Robinson Steam Electric Plant Security Personnel Training and Qualification Plan," with revisions submitted through January 16, 1987; and "H. B. Robinson Steam Electric Plant Safeguards Contingency Plan," with revisions submitted through March 27, 1986. Changes made in accordance with 10 CFR 73.55 shall be implemented in accordance with the schedule set forth therein.

G. The following programs shall be implemented and maintained by the licensee:

[5.5.10]

(1) A secondary water chemistry monitoring program to inhibit steam generator tube degradation. This program shall include: the identification of critical parameters, their sampling frequency, sampling points and control band limits; requirements for the documentation and review of sample results; the identification of the authority responsible for the interpretation of sample results; the procedures used to measure the critical parameters; and the procedures which identify the administrative events and corrective actions required to return the secondary chemistry to its normal control band following an out of control band condition.

(2) A program to reduce leakage from systems outside containment that would or could contain highly radioactive fluids during a serious transient or accident to as low as practical levels. This program shall include: provisions for preventive maintenance and periodic visual inspection requirements, and integrated leak test requirements for each system at a frequency not to exceed refueling cycle intervals.

See 5.5.2

No Change

(3) A program to determine the airborne iodine concentration in vital areas under accident conditions. This program shall include: training of personnel, procedures for monitoring, and provisions for maintenance of sampling and analysis equipment.

(4) A program to ensure the capability to obtain and analyze reactor coolant, radioactive iodines, and particulates in plant gaseous effluents, and containment atmosphere samples

See 5.5.3

Specification 5.5

(FOL DPR-23)

ITS

A1

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See 5.5.10

(2) A program to reduce leakage from systems outside containment that would or could contain highly radioactive fluids during a serious transient or accident to as low as practical levels. This program shall include: provisions for preventive maintenance and periodic visual inspection requirements, and integrated leak test requirements for each system at a frequency not to exceed refueling cycle intervals.

See 5.5.2

No Change

(3) A program to determine the airborne iodine concentration in vital areas under accident conditions. This program shall include: training of personnel, procedures for monitoring, and provisions for maintenance of sampling and analysis equipment.

[5.5.3]

(4) A program to ensure the capability to obtain and analyze reactor coolant, radioactive iodines, and particulates in plant gaseous effluents, and containment atmosphere samples

Supplement 8

Specification 5.5

(FOL DPR-23)

A1

ITS

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See 5.5.10

[5.5.2]

(2) A program to reduce leakage from systems outside containment that would or could contain highly radioactive fluids during a serious transient or accident to as low as practical levels. This program shall include: provisions for preventive maintenance and periodic visual inspection requirements, and integrated leak test requirements for each system at a frequency not to exceed refueling cycle intervals.

No CHANGE

(3) A program to determine the airborne iodine concentration in vital areas under accident conditions. This program shall include: training of personnel, procedures for monitoring, and provisions for maintenance of sampling and analysis equipment.

(4) A program to ensure the capability to obtain and analyze reactor coolant, radioactive iodines, and particulates in plant gaseous effluents, and containment atmosphere samples

See 5.5.3

The systems include RHR, SIS, CSS, Post Accident Containment Ventilation; and portions of CVCS, Liquid and gaseous waste Disposal, and Sampling.

M13

Supplement 8

ITS

A1

2.3 LIMITING SAFETY SYSTEM SETTINGS, PROTECTIVE INSTRUMENTATION

Applicability

Applies to trip settings for instruments monitoring reactor power and reactor coolant pressure, temperature, and flow and pressurizer level.

Objective

To provide for automatic protection action in the event that the principal process variables approach a safety limit.

Specification

L1

M1

[LCO 3.3.1] 2.3.1 Protective instrumentation settings for reactor trip shall be as follows:

OPERABLE

Add Note (1) to Table 3.3.1-1:
A channel is OPERABLE with a Nominal Trip Setpoint value found outside its calibration tolerance band provided the Trip Setpoint value is conservative with respect to its associated Allowable Value and the channel is re-adjusted to within the established calibration tolerance band of the Nominal Trip Setpoint.

2.3.1.1 Start-up protection

[T 3.3.1-1 (2.b)] a. High flux, power range ~~(low setpoint)~~ ~~≤ 25%~~ of rated power. 24

2.3.1.2 Core protection

[T 3.3.1-1 (2.a)] a. High flux, power range (high setpoint) ~~≤ 109%~~ of rated power 108

[T 3.3.1-1 (7.b)] b. High pressurizer pressure ~~≤ 2385~~ 2376 psig.

M1

[T 3.3.1-1 (7.a)] c. Low pressurizer pressure ~~≥ 1835~~ 1844 psig.

[T 3.3.1-1 (5)] d. Overtemperature Δ T

[NOTE 1]

L1

The OTΔT Function Allowable Value shall not exceed the following Nominal Trip Setpoint by more than 2.96% of ΔT span.

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

M20

Add Nominal Trip Setpoints

Intermediate Range Neutron Flux	25% thermal power
Source Range Neutron Flux	1.0E5 cps
Steam Generator water level low	30%
Coincident with Steam Flow/Feedwater Flow Mismatch	6.4E5 lbm/hr
Turbine Trip low autostop oil pressure	45 psig

[T3.3.1-1 (5)] [NOTE 1] (3) For each percent that the magnitude of $(q_t - q_b)$ exceeds -17% in the negative direction, the ΔT trip setpoint shall be automatically reduced by ~~2.4% of the value of ΔT at rated power (2300 Mwt)~~. A1

$2.4(q_b - q_T) - 17$ percent A2

[T3.3.1-1 (6)] [NOTE 2] e. Overpower Δ T

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

The OPΔT Function Allowable Value shall not exceed the following Nominal Trip Setpoint by more than 3.17% of ΔT span L1

where:

ΔT_o = Indicated ΔT at rated thermal power, °F;

T = Average temperature, °F;

T′ = 575.4°F Reference T_{avg} rated thermal power; M1

K_4 = ~~1.08~~, ≤ 1.06 L2

K_5 = 0.0 for decreasing average temperature, 0.02 sec/°F for increasing average temperature;

K_6 = 0.00277 for T > T′ and 0 for T ≤ T′;

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

$\frac{\tau_3 S}{1 + \tau_3 S}$ = The function generated by the rate-lag controller for T_{avg} dynamic compensation; LA1

τ_3 = Time constant utilized in the rate-lag controller for T_{avg}, τ_3 ~~≤ 10~~ ≥ 9 seconds; L2

f(ΔI) = As defined in d. above M1

[T3.3.1-1 (9)] f. Low reactor coolant loop flow ≥ ~~90%~~ 94.26 of normal indicated flow.

[T3.3.1-1 (12)] g. Low reactor coolant pump frequency ≥ ~~57.5~~ 58.2 Hz. a. Single loop b. Two loops A3

[T3.3.1-1 (11)] h. Undervoltage ≥ ~~70% of normal voltage~~ 3120

2.3.1.3 Other Reactor Trips

[T3.3.1-1 (8)] a. High pressurizer water level ≤ ~~92%~~ 91 of span. M1

[T3.3.1-1 (13)] b. Low-low steam generator water level ≥ ~~14%~~ 16 of narrow range instrument span.

ITS

A1

3.1.2 Heatup and Cooldown

3.1.2.1 The reactor coolant pressure and the system heatup and cooldown rates (with the exception of the pressurizer) shall be limited in accordance with Figure 3.1-1 and Figure 3.1-2 (for vessel exposure up to 24 EFPY). These limitations are as follows:

a. Over the temperature range from cold shutdown to hot operating conditions, the heatup rate shall not exceed 60°F/hr. in any one hour.

See 3.4.3

b. Allowable combinations of pressure and temperature for a specific cooldown rate are below and to the right of the limit lines for that rate as shown on Figure 3.1-2. This rate shall not exceed 100°F/hr. in any one hour. The limit lines for cooling rates between those shown in Figure 3.1-2 may be obtained by interpolation.

c. Primary system hydrostatic leak tests may be performed as necessary, provided the temperature limitation as noted on Figure 3.1-1 is not violated. Maximum hydrostatic test pressure should remain below 2350 psia.

[LCO 3.4.12.a.1] d. The overpressure protection system shall be OPERABLE[1], with both power operated relief valves OPERABLE with a lift setting of less than or equal to 420 psi whenever any RCS

nominal

A9

M35

400 psig and an allowable value of ≤ 418 (PORVs with lift settings, found between CHANNEL CALIBRATIONS, greater than the nominal lift setting but less than the allowable value are OPERABLE

[1] The overpressure protection system shall not be considered inoperable solely because either the normal or emergency power source for the PORV block valves is inoperable.

A8

Supplement 8

A1

TABLE 3.4-2

AUXILIARY FEEDWATER SYSTEM AUTOMATIC INITIATION SETPOINTS

ITS	FUNCTIONAL UNIT	SETTING LIMIT
	AUXILIARY FEEDWATER	
[T3.3.8-1(1)]	a. Steam Generator Water Level-low-low	≥ 16% of narrow range instrument span each steam generator (16) (M1)
[T3.3.8-1(4)]	b. Undervoltage - 4KV Busses 1 & 4	≥ 70% of 4KV Busses 1 & 4 Normal Voltage (3.3.2-1, Function 1)
[T3.3.8-1(2)]	c. S.I.	See Table 3.5-3, Item No. 1 and Table 3.5-1
[T3.3.8-1(3)]	d. Station Blackout	See Table 3.5-1, Item No. 6 — 328 V ± 10% with ≤ 1 sec. time delay

Add T 3.3.8-1 "Allowable Values (M12)

Add Note (1) to Table 3.3.8-1: (M1)

A channel is OPERABLE with an actual Trip Setpoint value found outside its calibration tolerance band provided the Trip Setpoint value is conservative with respect to its associated Allowable Value and the channel is re-adjusted to within the established calibration tolerance band of the Nominal Trip Setpoint.

Specification 3.3.2

A1

ITS

TABLE 3.5-1

ENGINEERED SAFETY FEATURE SYSTEM INITIATION INSTRUMENT SETTING LIMITS

	NO.	FUNCTIONAL UNIT	CHANNEL ACTION	SETTING LIMIT
[T3.3.2-1(1.c)]	1.	High Containment Pressure (HI Level)	Safety Injection*	≤ 5 (4) psig
[T3.3.2-1(2.c)]	2.	High Containment Pressure (HI-HI Level)	a. Containment Spray** b. Steam Line Isolation	≤ 25 (20) psig
[T3.3.2-1(1.d)]	3.	Pressurizer Low Pressure	Safety Injection*	≥ 1700 (1715) psig
[T3.3.2-1(1.e)]	4.	High Differential Pressure Between any Steam Line and the Steam Line Header	Safety Injection*	≤ 150 (100) psi
[T3.3.2-1(4.d,4.e)]	5.	High Steam Flow in 2/3 Steam Lines***	a. Safety Injection* b. Steam Line Isolation	≤ 40% (37.25) (at zero load) of full steam flow ≤ 40% (37.25) (at 20% load) of full steam flow ≤ 110% (109) (at full load) of full steam flow
		Coincident with Low T_{avg} or Low Steam Line Pressure		≥ 541 (543) °F T_{avg} ≥ 600 (614) psig steam line pressure
	6.	Loss of Power		
		a. 480V Emerg. Bus Undervoltage (Loss of Voltage) Time Delay	Trip Normal Supply Breaker	328 Volts ± 10% ≤ 1 sec when voltage is reduced to zero

M1

M1

See 3.3.5

Add Note (1) to Table 3.3.2-1:
A channel is OPERABLE with an actual Trip Setpoint value found outside its calibration tolerance band provided the Trip Setpoint value is conservative with respect to its associated Allowable Value and the channel is re-adjusted to within the established calibration tolerance band of the Nominal Trip Setpoint.

M1

Amendment No. 93

Supplement 8

Specification 3.1.4

A1

See ITS 3.3.1

TABLE 3.5-2 (Continued)

REACTOR TRIP INSTRUMENTATION LIMITING OPERATING CONDITIONS

NO.	FUNCTIONAL UNIT	1 TOTAL NO. OF CHANNELS	2 MINIMUM CHANNELS OPERABLE	3 OPERATOR ACTION IF COLUMN 1 OR 2 CANNOT BE MET	APPLICABLE CONDITIONS
11.	Turbine Trip				
	A. Auto Stop Oil Pressure	3	2	ACTION 6	*****
	B. Turb Stop Valves	2	2	ACTION 6	*****
12.	Lo Lo Steam Generator Water Level	3/SG	2/SG	ACTION 6	Reactor Critical
13.	Underfrequency 4 KV System	3	2	ACTION 6	Reactor Critical
14.	Undervoltage on 4 KV System	3	2	ACTION 6	Reactor Critical
15.	Control Rod Misalignment Monitor				Modes 1 and 2
	A. ERFIS Rod Position Deviation	1	1	ACTION 9	Reactor Critical
	B. Quadrant Power Tilt Monitor (upper and lower ex-core neutron detectors) "Detector Current Comparator"	1	1	ACTION 10	>50% of rated power

See ITS 3.3.1

Supplement 7

ITS

TABLE 3.5-2 (Continued)

REACTOR TRIP INSTRUMENTATION LIMITING OPERATING CONDITIONS

TABLE NOTATIONS

(a) * With ~~the reactor trip breakers closed~~ rod control system capable of rod withdrawal or one or more rods not fully inserted. (L35)

(b) ** Below the P-10 (Low Setpoint Power Range Neutron Flux Interlock) setpoint.

(d) *** Below the P-6 (Intermediate Range Neutron Flux Interlock) setpoint.

(h) **** Above the ~~P-10 (Low Setpoint Power Range Neutron Flux Interlock) setpoint or~~ P-7 (Turbine First Stage Pressure Interlock) setpoint and below the P-8 (Low Setpoint Power Range Neutron Flux Interlock) setpoint. (L5)

(f) ***** Above the ~~P-10 (Low Setpoint Power Range Neutron Flux Interlock) setpoint or~~ P-7 (Turbine First Stage Pressure Interlock) setpoint. (A30)

Add Note (c) (A31)

ACTION STATEMENTS

Add Note (e)

[ACTION B] ~~ACTION 1~~ With the number of OPERABLE channels one less than the Minimum Channels OPERABLE requirement, restore the inoperable channel to OPERABLE status within 48 hours, or be in the ~~Hot Shutdown condition~~ Mode 3 within ~~the next 6~~ hours and open RTBs in 55 hours. (L6)

[ACTION D] ~~ACTION 2~~ With the number of OPERABLE channels one less than the Total Number of Channels, Startup and/or Power Operation may proceed provided the following Conditions are satisfied: (L7)

Add RA D.2.2 "NOTE"

[ACTION E] a. The inoperable channel is placed in the tripped condition within ~~1~~ 6 hour. (L8)

[ACTION D] b. Either, thermal power is restricted to less than or equal to 75% of rated power ~~and the Power Range Neutron Flux trip setpoint is reduced to less than or equal to 85% of rated power within 4 hours; or, the Quadrant Power Tilt Ratio is monitored within 12 hours and every 12 hours thereafter using the movable incore detectors to confirm that the normalized symmetric power distribution is consistent with the indicated Quadrant Power Tilt Ratio~~ be in MODE 3 in 12 hours. (M6)

[ACTION E]

~~ACTION 3~~ With the number of channels OPERABLE one less than the Minimum Channels OPERABLE requirement and with the thermal power level:

[ACTION H] a. Below the P-6 (Intermediate Range Neutron Flux Interlock) setpoints, restore the inoperable channel to OPERABLE status prior to increasing thermal power above the P-6 setpoint.

[ACTION F] b. Above the P-6 (Intermediate Range Neutron Flux Interlock) setpoint but below 10% of rated power, ~~restore the inoperable channel to OPERABLE status prior to increasing thermal power above 10% of rated power.~~ (M7)

Reduce power to < P6 in 2 hours or increase power to > P10 in 2 hours. (L36)

With the number of channels OPERABLE one or two less than the Minimum Channels OPERABLE (L38)

Specification 3.1.4

See ITS 3.3.1

A1

TABLE 3.5-2 (Continued)

REACTOR TRIP INSTRUMENTATION LIMITING OPERATING CONDITIONS

TABLE NOTATIONS

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

ACTION 5 With the number of OPERABLE channels one less than the Minimum Channels OPERABLE requirement, verify compliance with Shutdown Margin within 1 hour and at least once per 12 hours thereafter.

ACTION 6 With the number of OPERABLE channels one less than the Total Number of Channels, Startup and/or Power Operation may proceed until performance of the next required operational test provided the inoperable channel is placed into the tripped condition within 1 hour.

ACTION 7 With the number of OPERABLE channels one less than the Total Number of Channels, place the inoperable channel into the tripped condition within 1 hour, and restore the inoperable channel to OPERABLE status within 7 days or be in at least the Hot Shutdown Condition within the next 8 hours.

ACTION 8 With the number of OPERABLE channels one less than the Minimum Channels OPERABLE requirement, restore the inoperable channel to OPERABLE status within 48 hours or open the Reactor Trip Breakers within the next hour.

L8

SR 3.1.4.1 2nd frequency

ACTION 9 Log individual rod position within ~~1 hour~~ 4 hours and every ~~hour~~ thereafter, ~~and following load changes of >10%~~ of rated power, or after >30 inches of control rod motion. In addition to the above ACTIONS, if both rod misalignment monitors (15.A and 15.B) are inoperable with reactor power >50% of rated power for 2 hours or more, the nuclear overpower trip shall be reset to ≤ 93% or rated power.

ACTION 10 Log individual upper and lower ion chamber currents within 1 hour and every hour thereafter, and following load changes of >10% of rated power, or abover >30 inches of control rod motion. In addition to the above ACTIONS, if both rod misalignment monitors (15.A and 15.B) are inoperable with reactor power >50% of rated power for two hours or more, the nuclear overpower trip shall be reset to ≤ 93 percent of rated power.

See ITS 3.3.1

Supplement 8

A1

TABLE 3.5-3 (Continued)

ITS

ENGINEERED SAFETY FEATURES INSTRUMENTATION LIMITING OPERATING CONDITIONS

TABLE NOTATIONS

Above Low Pressure SI Block Permit interlock.
Trip function may be blocked below Low T_{avg} Interlock setpoint. See 3.3.2
The reactor may remain critical below the Power Operating conditions with this feature inhibited for the purpose of starting reactor coolant pumps.

[Applicability Note]

ACTION 11 With the number of OPERABLE channels one less than the Minimum Channels OPERABLE requirement, restore the inoperable channel to OPERABLE status within 48 hours or be in at least the Hot Shutdown Condition within the next 8 hours and the Cold Shutdown Condition within the following 30 hours.

ACTION 12 With the number of OPERABLE channels one less than the Total Number of Channels. Power Operation may proceed until performance of the next required operational test provided the inoperable channel is placed into the tripped condition within 1 hour.

ACTION 13 With the number of OPERABLE channels one less than the Minimum Channels OPERABLE requirement, restore the inoperable channel to OPERABLE status within 1 hour or be in at least the Hot Shutdown Condition within the next 8 hours and the Cold Shutdown Condition within the following 30 hours.

L29

ACTION 14 With the number of OPERABLE channels per bus one less than the Total Number of Channels; place the inoperable channel into the ~~blocked~~ tripped condition within 1 hour, ~~and restore the inoperable channel to OPERABLE status within 48 hours or be in at least the Hot Shutdown Condition within the next 8 hours and the Cold Shutdown Condition within the following 30 hours.~~

[ACTION B] 6

[ACTION D]

Degraded voltage function

or enter applicable condition(s) and RA(s) for the associated DG made inoperable by LOP DG start instrumentation immediately

Add ACTION C M37

A1

TABLE 3.5-5 (Continued)

ITS

INSTRUMENTATION TO FOLLOW THE COURSE OF AN ACCIDENT

TABLE NOTATION

With one channel inoperable, restore the channel to OPERABLE status within 30 days

L.22

[ACTION A] [ACTION C] [ACTION B] [ACTION H] initiate action per 5.6.6

Note 4: With the number of OPERABLE Channels less than required by the Minimum Channels OPERABLE requirement, restore the inoperable Channel(s) to OPERABLE status within 7 days or, prepare and submit a Special Report to the NRC within the following 14 days detailing the cause of the inoperable Channel(s), the action being taken to restore the Channel(s) to operable status, the estimated date for completion of repairs, and any compensatory action being taken while the Channel(s) is inoperable.

See 5.6.6

[ACTION A] [ACTION B] initiate action per 5.6.6

Note 5: If one channel is inoperable, restore the channel to operable status within 30 days or, prepare and submit a special report to the NRC within the following 14 days detailing the cause(s) of the inoperable channels, the actions being taken to restore the channel to operable status, the estimated date for completion of the repairs, and the compensatory action being taken while the channel is inoperable. If both channels become inoperable and a pre-planned alternate method of monitoring is available, then restore at least one channel to operable status within 7 days or prepare and submit a special report to the NRC within the following 14 days detailing the cause(s) of the inoperable channels, the action being taken to restore at least one channel to operable status, the estimated date for completion of the repairs, and a description of the alternate method of monitoring the affected parameter while both channels are inoperable. If a pre-planned alternate method of monitoring the affected parameter is not available and implemented with both channels inoperable, then restore at least one channel to an operable status within 7 days or be in Hot Shutdown within 6 hours and ≤ 350°F within the following 30 hours.

See 5.6.6

L46

[ACTION C] [ACTION H]

See 5.6.6

L44

[ACTION E] [ACTION G]

Note 6: With both channels inoperable, restore at least one channel to an operable status within 14 days or be in Hot Shutdown within 6 hours and ≤ 200°F within the following 30 hours.

MODE 3

MODE 4

72 hours

6

L24

M31

L24

Add Functions & Requirements:

- SG Pressure
- Cont. Spray Additive Tank Level
- Cont. Isolation Valve Position Indication
- SG Level
- Power Range Neutron Flux
- Source Range Neutron Flux
- RCS Pressure
- RCS Hot Leg Temperature
- RCS Cold Leg Temperature
- RWST Level
- CST Level

M32

ITS

TABLE 4.1-1 (Continued)

	Channel Description	Check	Calibrate	Test	Remarks
21.	Containment Sump Level	N.A.	R	N.A.	See 3.4.15
[T3.3.1-1(15)] 22.	Turbine Trip Logic**	N.A.	~~N.A.~~ SR 3.3.1.10	~~R~~ SR 3.3.1.15	M17
23.	Accumulator Level and Pressure	S	R	N.A.	
24.	Steam Generator Pressure	S	R	M	LA4
[T3.3.1-1(17.e)] 25.	Turbine ~~First Stage~~ Impulse Pressure	~~S~~ SR 3.3.1.1	~~R~~ SR 3.3.1.10	~~M~~ SR 3.3.1.13	See ITS 3.3.2
26.	~~DELETED~~				L17
[T3.3.1-1(20)] 27.	Logic Channel Testing (Automatic Trip)	N.A.	N.A.	M(1) S/U(2) SR 3.3.1.5	Applicability MODES 1,2,3,4,5 (1) During hot shutdown and power operations. ~~When periods of reactor cold shutdown and refueling extend this interval beyond one month, this test shall be performed prior to startup.~~ (2) ~~Logic channel testing for nuclear source range channels shall only be required prior to each reactor startup, if not performed within the previous seven (7) days.~~ On a STAGGERED TEST BASIS
28.	~~DELETED~~				M18, M19, L18
[T3.3.1-1(12)] 29.	~~RPS~~ RCPs Frequency	N.A.	~~R~~ SR 3.3.1.10	~~S~~ SR 3.3.1.14	Add Note (j) to Table 3.3.1-1 A41

[T3.3.1-1(15)]** Stop valve closure or low EH fluid pressure.

[T3.3.1-1(17.a-d)] Add SR 3.3.1.11 and SR 3.3.1.13 for RPS interlocks P-6 P-8, P-10 and SR 3.3.1.13 and SR 3.3.1.14 for RPS interlock P-7 M14

Specification 3.3.1

Amendment No. ~~83~~, ~~106~~, ~~122~~, ~~127~~, 133 A1

Supplement 8

ITS

TABLE 4.1-1 (Continued)

MINIMUM FREQUENCIES FOR CHECKS, CALIBRATIONS AND TEST OF INSTRUMENT CHANNELS

	Channel Description	Check	Calibrate	Test	Remarks
	b. Main Vent Stack				See 3.3.3
	High Range	D	R	Q	
	Mid Range	D	R	Q	
	c. Spent Fuel Pit Lower Level				
	High Range	D	R	Q	M21
[T3.3.1-1(14)] 39.	Steam/Feedwater Flow Mismatch	~~N.A.~~ SR 3.3.1.1	~~N.A.~~ SR 3.3.1.10	~~N.A.~~ SR 3.3.1.7	L16
[T3.3.1-1(14)] 40.	Low Steam Generator Water Level	~~N.A.~~ SR 3.3.1.1	~~N.A.~~ SR 3.3.1.10	~~N.A.~~ SR 3.3.1.7	
41.	CV Level (Wide Range)+	M	R	R	
42.	CV Pressure (Wide Range)++	M	R	R	See 3.3.3
43.	CV Hydrogen Monitor+++	M	R	R	
44.	CV High Range Radiation Monitor++++	M	R#	R	See Relocated Specifications
45.	RCS High Point Vents	N.A.	N.A.	R	
[T3.3.1-1(1)] 46.	Manual Reactor Trip	N.A.	N.A.	~~R(1)~~ SR 3.3.1.14	A7
[T3.3.1-1(1,18,19)] 47.	Reactor Trip Bypass Breakers	N.A.	N.A.	~~M(3), R(4)~~ SR 3.3.1.4 SR 3.3.1.14	

~~(1) The manual reactor trip operational test shall verify the independent operability of the manual shunt trip circuit and the manual UV trip circuit on the reactor trip breakers. The test shall also verify the operability of the UV trip circuit on the bypass breakers.~~

~~(3) Remote manual UV trip required only when placing the bypass breaker in service.~~

~~(4) Perform UV trip from protection system.~~

L20

Add Note to SR 3.3.1.5 M53

Specification 3.3.1

A1

A1

ITS

TABLE 4.1-3

FREQUENCIES FOR EQUIPMENT TESTS

L3

M11

		Check	Frequency	Maximum Time Between Tests
1. [SR 3.1.4.3]	Control Rods	Rod drop times of all full length rods	Each refueling shutdown	NA* L3
2. [SR 3.1.4.2]	Control Rod	~~Partial~~ movement of all full length rods	~~Every 2 weeks during reactor critical operations~~	~~20 days~~
3.	Pressurizer Safety Valves	Set point	Each refueling shutdown	NA
4.	Main Steam Safety Valves	~~Verify each~~ required MSSV lift setpoint per Table 4.1-4 in accordance with the Inservice Testing Program. Following testing, lift setting shall be within +/- 1%.	In accordance with the Inservice Testing Program	NA
5.	Containment Isolation Trip	Functioning	Each refueling shutdown	NA
6.	Refueling System Interlocks	Functioning	Prior to each refueling shutdown	NA
7.	Service Water System	Functioning	Each refueling shutdown	NA
8.	~~DELETED~~			
9.	Primary System Leakage	Evaluate	Daily when reactor coolant system is above cold shutdown condition	NA
10.	Diesel Fuel Supply	Fuel Inventory	Weekly	10 days
11.	~~DELETED~~			
12.	Turbine Steam Stop, Control, Reheat Stop, and Interceptor Valves	Closure	Quarterly during power operation and prior to startup	115 days

Not fully Inserted

≥ 10 steps

92 days

See 3.4.10

See 3.7.1

See 3.6.3 3.3.2

See 3.9.1

See 3.7.7

See 3.4.13

See 3.8.3

See 3.7.1

Add SR 3.1.4.1 and first frequency

M12