

VI. PROPOSED TECHNICAL SPECIFICATIONS REVISIONS

The Technical Specifications for HNP-1 (Appendix A to Operating License DPR-57) are proposed for revision as presented in this section. Table 6.1 provides the instructions for incorporating the revision(s).

TABLE 6.1

INSTRUCTIONS FOR INCORPORATING TECHNICAL SPECIFICATIONS REVISIONS

If the Technical Specifications revisions are accepted as proposed, the HNP-1 Technical Specifications (Appendix A to Operating License DPR-57) should be incorporated as follows:

<u>Item</u>	<u>Deletions (Page)</u>	<u>Insertions (Page)</u>	<u>Applicable SER*(a) Section(s)</u>
1	1.1-3	1.1-3	4.B.4
2	1.1-5	1.1-5	4.B.4
3	Fig. 2.1-1	Fig. 2.1-1	4.B.4
4	1.2-2	1.2-2	4.B.7
5	1.2-6	1.2-6	4.B.7
6	3.1-4	3.1-4	4.B.4, 4.B.7
7	3.1-7	3.1-7	ATTS
8	3.1-12	3.1-12	4.B.7
9	3.2-2	3.2-2	4.B.4, 4.B.6, 4.B.7,
10	3.2-3	3.2-3	4.B.6, 4.B.7
11	3.2-5	3.2-5	4.B.4, 4.B.6, 4.B.7
12	3.2-6	3.2-6	4.B.6, 4.B.7
13	3.2-8	3.2-8	4.B.1, 4.B.4, 4.B.6, 4.B.7
14	3.2-9	3.2-9	4.B.6, 4.B.7
15	3.2-10	3.2-10	4.B.2, 4.B.4, 4.B.6, 4.B.7
16	3.2-11	3.2-11	4.B.2, 4.B.4, 4.B.5, 4.B.6, 4.B.7
17	3.2-12	3.2-12	4.B.6, 4.B.7
18	3.2-14	3.2-14	4.B.1, 4.B.4, 4.B.5, 4.B.6, 4.B.7
19	3.2-22	3.2-22	4.B.3, 4.B.6
20	3.2-24	3.2-24	ATTS, 4.B.6
21	3.2-25	3.2-25	ATTS, 4.B.6
22	3.2-27	3.2-27	ATTS, 4.B.6
23	3.2-28	3.2-28	ATTS, 4.B.6
24	3.2-30	3.2-30	ATTS, 4.B.6
25	3.2-31	3.2-31	ATTS, 4.B.6
26	3.2-32	3.2-32	ATTS
27	3.2-33	3.2-33	ATTS
28	3.2-34	3.2-34	ATTS
29	3.2-35	3.2-35	ATTS, 4.B.6, 4.B.7
30	3.2-36	3.2-36	ATTS
31	3.2-38	3.2-38	ATTS, 4.B.6, 4.B.7
32	3.2-39	3.2-39	ATTS
33	3.2-48	3.2-48	4.B.3, 4.B.6
34	3.2-49	3.2-49	4.B.3
35	3.2-50	3.2-50	4.B.4
36	3.2-50a	3.2-50a	4.B.4
37	3.2-51	3.2-51	4.B.7
38	3.2-52	3.2-52	4.B.4, 4.B.6, 4.B.7
39	3.2-53	3.2-53	ATTS, 4.B.6, 4.B.7
40	3.2-54	3.2-54	4.B.6, 4.B.7

<u>Item</u>	<u>Deletions (Page)</u>	<u>Insertions (Page)</u>	<u>Applicable SER*(a) Section(s)</u>
41	3.2-55	3.2-55	ATTS, 4.B.4, 4.B.6, 4.B.7
42	3.2-56	3.2-56	ATTS, 4.B.6, 4.B.7
43	3.2-57	3.2-57	4.B.6, 4.B.7
44	3.2-58	3.2-58	4.B.4, 4.B.7
45	3.2-59	3.2-59	4.B.7
46	3.2-60	3.2-60	4.B.4, 4.B.5, 4.B.6, 4.B.7
47	3.2-61	3.2-61	ATTS, 4.B.4, 4.B.6, 4.B.7
48	3.2-62	3.2-62	4.B.4, 4.B.5, 4.B.7
49	3.2-63	3.2-63	ATTS, 4.B.7
50	3.7-19	3.7-19	4.B.6

* SER - Safety Evaluation Report

- a. 1. ATTS refers to proposed revisions justified in Section III of this submittal.
2. 4B.1 through 4B.7 refer to justifications presented in Section IV of this submittal.

- 2.1.A.1.d APRM Rod Block Trip Setting
This section deleted

- 2.1.A.2. Reactor Vessel Water Low Level Scram
Trip Setting (Level 3)

Reactor vessel water low level scram trip setting (Level 3) shall be ≥ 10.0 inches (narrow range scale). |

3. Turbine Stop Valve Closure Scram

Turbine stop valve closure scram trip setting shall be ≤ 10 percent valve closure from full open. This scram is only effective when turbine steam flow is above that corresponding to 30% of rated core thermal power, as measured by turbine first stage pressure.

2.1.B. Reactor Vessel Water Level Trip Settings
Which Initiate Core Standby Cool-
ing Systems (CSCS)

Reactor vessel water level trip settings which initiate core standby cooling systems shall be as shown in Tables 3.2-2 thru 3.2-6 at normal operating conditions.

1. HPCI Actuation (Level 2)

HPCI actuation (Level 2) shall occur at a water level ≥ -47 inches. |

2. Core Spray and LPCI Actuation (Level 1)

Core Spray and LPCI actuation (Level 1) shall occur at a water level ≥ -113 inches. |

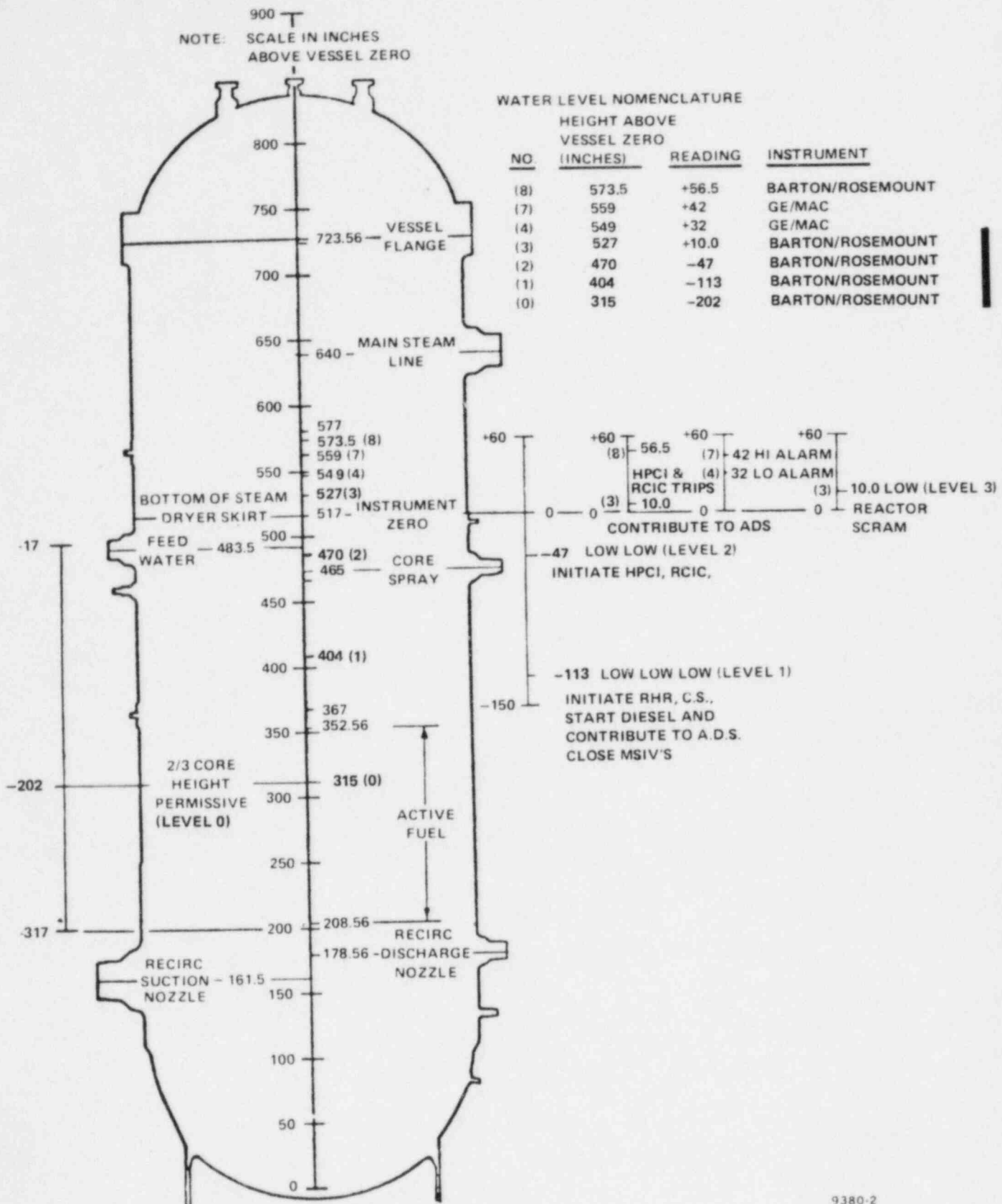


FIGURE 2.1-1
REACTOR VESSEL WATER LEVEL

2.2.A Nuclear System Pressure (cont.)

The allowable setpoint relief error for each valve shall be + 1%. In the event that an installed safety-relief valve requires replacement, a spare valve whose setpoint is lower than that of the failed valve may be substituted for the failed valve until the first refueling outage following such substitution. No more than two valves with lower setpoints may be substituted in place of valves with higher setpoints. Spare valves which are used as substitutes under the abovementioned provisions shall have a setpoint equal to 1080 psig $\pm 1\%$ or 1090 psig $\pm 1\%$.

1.2.A.2. When Operating The RHR System in the Shutdown Cooling Mode

The reactor vessel steam dome pressure shall not exceed 162 psig at any time when operating the RHR system in the Shutdown Cooling Mode.

2.1.A.2. When Operating The RHR System in the Shutdown Cooling Mode

The reactor pressure trip setting which closes (on increasing pressure) or permits opening (on decreasing pressure) of the shutdown cooling isolation valves shall be ≤ 145 psig. |

2.2 REACTOR COOLANT SYSTEM INTEGRITY

A. Nuclear System Pressure

1. When Irradiated Fuel is in the Reactor

The 11 relief/safety valves are sized and set point pressures are established in accordance with the following requirements of Section III of the ASME Code:

- a. The lowest relief/safety valve must be set to open at or below vessel design pressure and the highest relief/safety valve must be set to open at or below 105% of design pressure.
- b. The valves must limit the reactor pressure to no more than 110% of design pressure.

The primary system relief/safety valves are sized to limit the primary system pressure, including transients, to the limits expressed in the ASME Boiler and Pressure Vessel Code, Section III, Nuclear Vessels. No credit is taken from a scram initiated directly from the isolation event, or for power operated relief/safety valves, sprays, or other power operated pressure relieving devices. Thus, the probability of failure of the turbine-generator trip SCRAM or main steam isolation valve closure SCRAM is conservatively assumed to be unity. Credit is taken for subsequent indirect protection system action such as neutron flux SCRAM and reactor high pressure SCRAM, as allowed by the ASME Code. Credit is also taken for the dual relief/safety valves in their ASME Code qualified mode of safety operation. Sizing on this basis is applied to the most severe pressurization transient, which is the main steam isolation valves closure, starting from operation at 105 percent of the reactor warranted steamflow condition.

Reference 2, Figure 4 shows peak, vessel bottom pressures attained when the main steam isolation valve closure transients are terminated by various modes of reactor scram, other than that which would be initiated directly from the isolation event (trip scram). Relief/safety valve capacities for this analysis are 84.0 percent, representative of the 11 relief/safety valves.

The relief/safety valve settings satisfy the Code requirements for relief/safety valves that the lowest valve set point be at or below the vessel design pressure of 1250 psig. These settings are also sufficiently above the normal operating pressure range to prevent unnecessary cycling caused by minor transients. The results of postulated transients where inherent relief/safety valve actuation is required are given in Section 14.3 of the FSAR.

2. When Operating the RHR System in the Shutdown Cooling Mode

An interlock exists in the logic for the RHR shutdown cooling valves, which are normally closed during power operation, to prevent opening of the valves above a preset pressure setpoint of 145 psig. This setpoint is selected to assure that pressure integrity of the RHR system is maintained. Administrative operating procedures require the operator to

Table 3.1-1 (Cont'd)

Scram Number (a)	Source of Scram Trip Signal	Operable Channels Required Per Trip System (b)	Scram Trip Setting	Source of Scram Signal is Required to be Operable Except as Indicated Below
5	Drywell Pressure -High	2	≤ 1.92 psig	Not required to be operable when primary containment integrity is not required. May be bypassed when necessary during purging for containment inerting or deinerting.
6	Reactor Vessel Water Level - Low (Level 3)	2	≥ 10.0 inches	
7	Scram Discharge Volume (High High Level)			Permissible to bypass (initiates control rod block) in order to reset RPS when the Mode Switch is in the REFUEL or SHUTDOWN position.
	a. Float Switches	2	≤ 71 gallons	
	b. Thermal Level Sensors	2	≤ 71 gallons	
8	APRM Flow Referenced Simulated Thermal Power Monitor	2	$S < 0.66W + 62\%$ (Not to exceed 117%) Tech Spec 2.1.A.1.c (1)	
	Fixed High-High Neutron Flux	2	$S < 120\%$ Power Tech Spec 2.1.A.1.c (2)	
	Inoperative	2	Not Applicable	An APRM is inoperable if there are less than two LPRM inputs per level or there are less than 11 LPRM inputs to the APRM channel.

Table 4.1-1

Reactor Protection System (RPS) Instrumentation Functional Test, Functional
Test Minimum Frequency, and Calibration Minimum Frequency

Scram Number (a)	Source of Scram Trip Signal	Group (b)	Instrument Functional Test Minimum Frequency (c)	Instrument Calibration Minimum Frequency
1	Mode Switch in SHUTDOWN	A	Once/Operating Cycle	Not Applicable
2	Manual Scram	A	Every 3 months	Not Applicable
3	IRM High High Flux	C	Once/Week during refueling and within 24 hours of Startup (e)	Once/Week
	Inoperative	C	Once/week during refueling and within 24 hours of Startup (e)	Once/Week
4	Reactor Vessel Steam Dome Pressure - High	D	Once/Month	Once/operating cycle
5	Drywell Pressure-High	D	Once/Month	Once/operating cycle
6	Reactor Vessel Water Level - Low (Level 3)	D	Once/Month (g)	Once/Operating Cycle
7	Scram Discharge Volume High High Level			
	a. Float Switches	A	Once/Month (f)	(h)
	b. Thermal Level Sensors	B	Once/Month (f)	Once/operating cycle
8	APRM Fixed High-High Flux	B	Once/Week (e)	Twice/Week
	Inoperable	B	Once/Week (e)	Twice/Week
	Downscale	B	Once/Week (e)	Twice/Week
	Flow Reference Simulated Thermal Power Monitor	B	Once/Week (f)	Once/Operating Cycle
	15% Flux	C	Within 24 Hours of Startup (e)	Once/Week

3.1.A.4. Reactor Vessel Steam Dome Pressure - High (Continued)

setting also protects the core from exceeding thermal hydraulic limits as a result of pressure increases from some events that occur when the reactor is operating at less than rated power and flow.

5. Drywell Pressure - High

High pressure in the drywell could indicate a break in the primary pressure boundary system. The reactor is tripped to minimize the possibility of fuel damage and reduce the amount of energy being added to the coolant. The trip setting was selected as low as possible without causing spurious trips.

6. Reactor Vessel Water Level - Low (Level 3)

The bases for the Reactor Vessel Water Level-Low Scram Trip Setting (Level 3) are discussed in the bases for Specification 2.1.A.2.

7. Scram Discharge Volume High High Level

The control rod drive scram system is designed so that all of the water which is discharged from the reactor by a scram can be accommodated in the discharge piping. A part of this piping is an instrument volume which is the low point in the piping. No credit was taken for this volume in the design of the discharge piping as concerns the amount of water which must be accommodated during a scram. During normal operation the discharge volume is empty; however, should the discharge volume fill with water, the water discharged to the piping from the reactor could not be accommodated which would result in a slow scram time or partial or no control rod insertion. To preclude this occurrence, level switches have been provided in the instrument volume which scram the reactor when the volume of water reaches 71 gallons. As indicated above, there is sufficient volume in the piping to accommodate the scram without impairment of the scram times or amount of insertion of the control rods. This function shuts the reactor down while sufficient volume remains to accommodate the discharged water and precludes the situation in which a scram would be required but not able to perform its function adequately.

8. APRM

Three APRM instrument channels are provided for each protection trip system. APRM's A and E operate contacts in one trip logic and APRM's C and E operate contacts in the other trip logic. APRM's B, D and F are arranged similarly in the other protection trip system. Each protection trip system has one more APRM than is necessary to meet the minimum number required per channel. This allows the bypassing of one APRM per protection trip system for maintenance, testing or calibration.

a. Flow Referenced Simulated Thermal Power Monitor and Fixed High-High Neutron Flux

The bases for the APRM Flow Referenced Simulated Thermal Power Monitor and Fixed High-High Neutron Flux Scram Trip Settings are discussed in the bases for Specification 2.1.A.1.c.

Table 3.2-1

INSTRUMENTATION WHICH INITIATES REACTOR VESSEL AND PRIMARY
CONTAINMENT ISOLATION

Ref. No. (a)	Instrument	Trip Condition Nomenclature	Required Operable Channels per Trip System (b)	Trip Setting	Action to be taken if number of channels is not met for both trip systems (c)	Remarks (d)
1	Reactor Vessel Water Level	Low (Level 3) Narrow Range	2	≥ 10.0 inches	Initiate an orderly shutdown and achieve the Cold Shutdown Condition within 24 hours or isolate the shutdown cooling system.	Initiates Group 2 & 6 isolation.
		Low Low (Level 2)	2	≥ -47 inches	Initiate an orderly shutdown and achieve the Cold Shutdown Condition within 24 hours.	Starts the SGTS, initiates Group 5 isolation, and initiates secondary containment isolation.
		Low Low Low (Level 1)	2	≥ -113 inches	Initiate an orderly shutdown and achieve the Cold Shutdown Con- dition within 24 hours.	Initiates Group 1 isolation.
2	Reactor Vessel Steam Dome Pressure (Shut- down Cooling Mode)	Low Permissive	1	≤ 145 psig	Isolate shutdown cooling.	Isolates the shutdown cooling suction valves of the RHR system.
3	Drywell Pressure	High	2	≤ 1.92 psig	Initiate an orderly shutdown and achieve the Cold Shutdown Condition within 24 hours	Starts the standby gas treatment system, initiates Group 2 isolation and second- ary containment isolation.

Table 3.2-1 (Cont.)

Ref. No. (a)	Instrument	Trip Condition Nomenclature	Required Operable Channels per Trip System (b)	Trip Setting	Action to be taken if number of channels is not met for both trip systems (c)	Remarks (d)
4	Main Steam Line Radiation	High	2	<3 times normal full power back- ground	Initiate an orderly load reduction and close MSIVs within 8 hours.	Initiates Group 1 isolation.
5	Main Steam Line Pressure	Low	2	>825 psig	Initiate an orderly load reduction and close MSIVs within 8 hours.	Initiates Group 1 isolation. Only required in RUN mode, therefore activated when Mode Switch is in RUN position.
6	Main Steam Line Flow	High	2	<138% rated flow (≤115 psid)	Initiate an orderly load reduction and close MSIVs within 8 hours.	Initiates Group 1 isolation.
7	Main Steam Line Tunnel Temperature	High	2	≤194°F	Initiate an orderly load reduction and close MSIVs within 8 hours.	Initiates Group 1 isolation
8	Reactor Water Cleanup System Differential Flow	High	1	20-80 gpm	Isolate reactor water cleanup system.	Final trip setting will be determined during startup test program.
9	Reactor Water Cleanup Area Temperature	High	2	≤124°F	Isolate reactor water cleanup system.	
10	Reactor Water Cleanup Area Ventilation Differential Temperature	High	2	≤67°F	Isolate reactor water cleanup system.	
11	Condenser Vacuum	Low	2	>7" Hg. vacuum	Initiate an orderly load reduction and close MSIVs within 8 hrs.	Initiate Group 1 isolation

Table 3.2-2

INSTRUMENTATION WHICH INITIATES OR CONTROLS HPCI

Ref. No. (a)	Instrument	Trip Condition Nomenclature	Required Operable Channels per Trip System (b)	Trip Setting	Remarks
1.	Reactor Vessel Water Level	Low Low (Level 2)	2	≥ -47 inches	Initiates HPCI; Also initiates RCIC.
2.	Drywell Pressure	High	2	≤ 1.92 psig	Initiates HPCI; Also initiates LPCI and Core Spray and provides a permissive signal to ADS.
3.	HPCI Turbine Overspeed	Mechanical	1	≤ 5000 rpm	Trips HPCI turbine
4.	HPCI Turbine Exhaust Pressure	High	1	≤ 146 psig	Trips HPCI turbine
5.	HPCI Pump Suction Pressure	Low	1	< 12.6 inches Hg vacuum	Trips HPCI turbine
6.	Reactor Vessel Water level	High (Level 8)	2	$\leq +56.5$ inches	Trips HPCI turbine
7.	HPCI Pump Discharge Flow	High	1	≥ 870 gpm (≥ 9.04 inches)	Closes HPCI minimum flow bypass line to suppression chamber.
		Low	1	< 605 gpm (< 4.36 inches)	Opens HPCI minimum flow bypass line if pressure permissive is present.
8.	HPCI Emergency Area Cooler Ambient Temperature	High	1	$\leq 169^{\circ}\text{F}$	Closes isolation valves in HPCI system, trips HPCI turbine.

Table 3.2-2 (Cont.)

Ref. No. (a)	Instrument	Trip Condition Nomenclature	Required Operable Channels per Trip System (b)	Trip Setting	Remarks
9.	HPCI Steam Supply Pressure	Low	2	≥ 100 psig	Closes isolation valves in HPCI system, trips HPCI turbine.
10.	HPCI Steam Line ΔP (Flow)	High	1	$< 303\%$ rated flow	Close isolation valves in HPCI system, trips HPCI turbine.
11.	HPCI Turbine Exhaust Diaphragm Pressure	High	1	≤ 20 psig	Close isolation valves in HPCI system, trips HPCI turbine.
12.	Suppression Chamber Area Ambient Temperature	High	1	$\leq 169^\circ\text{F}$	Close isolation valves in HPCI system, trips HPCI turbine.
13.	Suppression Chamber Area Differential Air temperature	High	1	$\leq 42^\circ\text{F}$	Close isolation valves in HPCI system, trips HPCI turbine.
14.	Condensate Storage Tank Level	Low	2	≥ 0 inches	Automatic interlock switches suction from CST to suppression chamber.
15.	Suppression Chamber Water Level	High	2	≤ 154.2 inches with respect to torus invert	Automatic interlock switches suction from CST to suppression chamber.
16.	HPCI Logic Power Failure Monitor		1	Not Applicable	Monitors availability of power to logic system.

a. The column entitled "Ref. No." is only for convenience so that a one-to-one relationship can be established between items in Table 3.2-2 and items in Table 4.2-2.

Table 3.2-3

INSTRUMENTATION WHICH INITIATES OR CONTROLS RCIC

Ref. No. (a)	Instrument	Trip Condition Nomenclature	Required Operable Channels per Trip System (b)	Trip Setting	Remarks
1.	Reactor Vessel Water Level	Low Low (Level 2)	2	≥ -47 inches	Initiates RCIC; also initiates HPCI.
2.	RCIC Turbine Overspeed	Electrical	1	$\leq 110\%$ rated	Trips RCIC turbine.
		Mechanical	1	$\leq 125\%$ rated	Trips RCIC turbine.
3.	RCIC Turbine Exhaust Pressure	High	1	$\leq +45$ psig	Trips RCIC turbine.
4.	RCIC Pump Suction Pressure	Low	1	≤ 12.6 inches Hg Vacuum	Trips RCIC turbine.
5.	Reactor Vessel Water Level	High (Level 8)	2	$\leq +56.5$ inches	Trips RCIC; automatically resets when water drops below level 8, system automatically restarts at level 2.
6.	RCIC Pump Discharge Flow	High	1	> 87 gpm (> 10.6 inches)	Closes RCIC minimum flow bypass line to suppression chamber.
		Low	1	≤ 53 gpm (≤ 3.87 inches)	Opens RCIC minimum flow bypass line if pressure permissive is present.
7.	RCIC Emergency Area Cooler Ambient Temperature	High	1	$\leq 169^\circ\text{F}$	Closes isolation valves in RCIC system, trips RCIC turbine.

Table 3.2-3 (cont.)

Ref. No. (a)	Instrument	Trip Condition Nomenclature	Required Operable Channels per Trip System (b)	Trip Setting	Remarks
8.	RCIC Steam Supply Pressure	Low	2	≥ 60 psig	Closes isolation valves in RCIC system, trips RCIC turbine.
9.	RCIC Steam Line ΔP (Flow)	High	1	$< 306\%$ rated flow	Closes isolation valves in RCIC system, trips RCIC turbine.
10.	RCIC Turbine Exhaust Diaphragm Pressure	High	1	≤ 20 psig	Closes isolation valves in RCIC system, trips RCIC turbine.
11.	Suppression Chamber Area Ambient Temperature	High	1	$\leq 169^\circ\text{F}$	Closes isolation valves in RCIC system, trips RCIC turbine.
12.	Suppression Chamber Area Differential Air Temperature	High	1	$\leq 42^\circ\text{F}$	Closes isolation valves in RCIC system, trips RCIC turbine.
13.	RCIC Logic Power Failure Monitor		1	Not Applicable	Monitors availability of power to logic system.
14.	Condensate Storage Tank Water Level	Low	2	≥ 0 "	Transfers suction from CST to suppression pool
15.	Suppression Pool Water Level	High	2	< 0 "	Transfers suction from CST to suppression pool

Table 3.2-4

INSTRUMENTATION WHICH INITIATES OR CONTROLS ADS

Ref. No. (a)	Instrument	Trip Condition Nomenclature	Required Operable Channels per Trip System (b)	Trip Setting	Remarks
1.	Reactor Vessel Water Level	Low (Level 3)	1	≥ 10.0 inches	Confirms low level, ADS permissive
	Reactor Vessel Water Level	Low Low Low (Level 1)	2	≥ -113 inches	Permissive signal to ADS timer
2.	Drywell Pressure	High	2	≤ 1.92 psig	Initiates HPCI; also initiates LPCI and core spray and provides a permissive signal to ADS timer
3.	RHR Pump Discharge Pressure	High	2	≥ 112 psig	Permissive signal to ADS timer
4.	CS Pump Discharge Pressure	High	2	≥ 137 psig	Permissive signal to ADS timer
5.	Auto Depressurization Timer		1	120 ± 12 seconds	With Level 3 and Level 1 and high drywell pressure and CS or RHR pump at pressure, timing sequence begins. If the ADS timer is not reset it will initiate ADS.
6.	Automatic Blowdown Control Power Failure Monitor		1	Not applicable	Monitors availability of power to logic system

a. The column entitled "Ref. No." is only for convenience so that a one-to-one relationship can be established between items in Table 3.2-4 and items in Table 4.2-4.

b. Whenever any CCCS subsystem is required to be operable by Section 3.5, there shall be two operable trip systems. If the required number of operable channels cannot be met for one of the trip systems, that system shall be repaired or the reactor shall be placed in the Cold Shutdown Condition within 24 hours after this trip systems is made or found to be inoperable.

Table 3.2-5

INSTRUMENTATION WHICH INITIATES OR CONTROLS THE LPCI MODE OF RHR

Ref. No. (a)	Instrument	Trip Condition Nomenclature	Required Operable Channels per Trip System (b)	Trip Setting	Remarks
1.	Reactor Vessel Water Level	Low Low Low (Level 1)	2	≥ -113 inches	Initiates LPCI mode of RHR
2.	Drywell Pressure	High	2	≤ 1.92 psig	Initiates LPCI mode of RHR. Also initiates HPCI and Core Spray and provides a permissive signal to ADS
3.	Reactor Vessel Steam Dome Pressure	Low Permissive	1	≤ 145 psig	With primary containment isolation signal, closes RHR (LPCI) inboard motor operated injection valves
		Low	2	≥ 335 psig	Permissive to close Recirculation Discharge Valve and Bypass Valve
		Low	2	≥ 460 psig	Permissive to open LPCI injection valves
4.	Reactor Shroud Water Level	Low (Level 0)	1	≥ -202 inches	Acts as permissive to divert some LPCI flow to containment spray
5.	LPCI Cross Connect Valve Open Annunciator	N/A	1	Valve not closed	Initiates annunciator when valve is not closed

Table 3.2-5 (Cont.)

INSTRUMENTATION WHICH INITIATES OR CONTROLS THE LPCI MODE OF RHR

Ref. No. (a)	Instrument	Trip Condition Nomenclature	Required Operable Channels per Trip System (b)	Trip Setting	Remarks
6	RHR (LPCI) Pump Flow	Low	1	>1670 gpm (4.7 inches)	Opens LPCI minimum flow line upon receipt of low flow signal from both pumps and closes LPCI minimum flow line when signal from either pump is not present
7	RHR(LPCI) Pump Start Timers		1	0<t<1 seconds	With loss of normal power, and upon receipt of emergency power, one RHR pump starts immediately, the other three follow in 10 seconds
			1	9<t<11 seconds	
8	Valve Selection Timers		1	≥10 minutes	Cancels LPCI injection valve initiation signal
9	RHR Relay Logic Power Failure Monitor		1	Not Applicable	Monitors availability of power to logic system

Table 3.2-6

INSTRUMENTATION WHICH INITIATES OR CONTROLS CORE SPRAY

Ref. No. (a)	Instrument	Trip Condition Nomenclature	Required Operable Channels per Trip System (b)	Trip Setting	Remarks
1.	Reactor Vessel Water Level	Low Low Low (Level 1)	2	≥ -113 inches	Initiates CS.
2.	Drywell Pressure	High	2	≤ 1.92 psig	Initiates CS. Also initiates HPCI and LPCI Mode of RHR and provides a permissive signal to ADS
3.	Reactor Vessel Steam Dome Pressure	Low	2	≥ 460 psig	Permissive to open CS injection valves.
4.	Core Spray Sparger Differential Pressure		1	To be determined during startup testing	Monitors integrity of CS piping inside vessel and core shroud.
5.	CS Pump Discharge Flow	Low	1	≥ 610 gpm (≥ 4.13 inches)	Minimum flow bypass line is closed when low flow signal is not present.
6.	Core Spray Logic Power Failure Monitor		1	Not Applicable	Monitors availability of power to logic system.

a. The column entitled "Ref. No." is only for convenience so that a one-to-one relationship can be established between items in Table 3.2-6 and items in Table 4.2-6.

b. Whenever any CCCS subsystem is required to be operable by Section 3.5, there shall be two operable trip systems. If the required number of operable channels cannot be met for one of the trip systems, that system shall be repaired or the reactor shall be placed in the Cold Shutdown Condition within 24 hours after this trip system is made or found to be inoperable.

Table 3.2-11

INSTRUMENTATION WHICH PROVIDES SURVEILLANCE INFORMATION

Ref. No. (a)	Instrument (b)	Required Operable Instrument Channels	Type and Range	Action	Remarks
1	Reactor Vessel Water Level	1 2	Recorder -150" to +60" Indicator -150" to +60"	(c) (c)	(d) (d)
2	Shroud Water Level	1 1	Recorder -317" to -17" Indicator -317" to -17"	(c) (c)	(d) (d)
3	Reactor Pressure	1 2	Recorder 0 to 1500 psig Indicator 0 to 1500 psig	(c) (c)	(d) (d)
4	Drywell Pressure	2	Recorder -10 to +90 psig	(c)	(d)
5	Drywell Temperature	2	Recorder 0 to 500°F	(c)	(d)
6	Suppression Chamber Air Temperature	2	Recorder 0 to 500°F	(c)	(d)
7	Suppression Chamber Water Temperature	2	Recorder 0 to 250°F	(c)	(d)
8	Suppression Chamber Water Level	2 2	Indicator 0 to 300" Recorder 0 to 30"	(c) (c)(e)	(d) (d)
9	Suppression Chamber Pressure	2	Recorder -10 to +90 psig	(c)	(d)
10	Rod Position Information System (RPIS)	1	28 Volt Indicating Lights	(c)	(d)
11	Hydrogen and Oxygen Analyzer	1	Recorder 0 to 52	(c)	(d)
12	Post LOCA Radiation Monitoring System	1	Recorder Indicator 1 to 10 ⁶ R/hr	(c) (c)	(d) (d)
13	a) Safety/Relief Valve Position Primary Indicator	1/SRV	Indicating Light at 85 psig	(f)	
	b) Safety/Relief Valve Position Secondary Indicator	1	Recorder 0 to 600°F	(f)	

Table 4.2-1

Check, Functional Test, and Calibration Minimum Frequency for Instrumentation
Which Initiates Reactor Vessel and Primary Containment Isolation

Ref. No. (a)	Instrument	Instrument Check Minimum Frequency	Instrument Functional Test Minimum Frequency (b)	Instrument Calibration Minimum Frequency (c)
1	Reactor Vessel Water Level (Levels 1, 2, and 3)	Once/shift	Once/month	Once/operating cycle
2	Reactor Vessel Steam Dome Pressure (Shutdown Cooling Mode)	Once/shift	Once/month	Once/operating cycle
3	Drywell Pressure	Once/shift	Once/month	Once/operating cycle
4	Main Steam Line Radiation	None	Once/week (e)	Every 3 months (f)
5	Main Steam Line Pressure	None	(d)	Every 3 months
6	Main Steam Line Flow	Once/shift	Once/month	Once/operating cycle
7	Main Steam Line Tunnel Temperature	Once/shift	Once/month	Once/operating cycle
8	Reactor Water Cleanup System Differential Flow	None	(d)	Every 3 months
9	Reactor Water Cleanup Area Temperature	Once/shift	Once/month	Once/operating cycle

Table 4.2-1 (Cont'd)

Ref. No. (a)	Instrument	Instrument Check Minimum Frequency	Instrument Functional Test Minimum Frequency (b)	Instrument Calibration Minimum Frequency (c)
10	Reactor Water Cleanup Area Ventilation Differential Temperature	Once/shift	Once/month	Once/operating cycle
11	Condenser Vacuum	None	(d)	Every 3 months

Notes for Table 4.2-1

- a. The column entitled "Ref. No." is only for convenience so that a one-to-one relationship can be established between items in Table 4.2-1 and items in Table 3.2-1.
- b. Instrument functional tests are not required when the instruments are not required to be operable or are tripped. However, if functional tests are missed, they shall be performed prior to returning the instrument to an operable status.
- c. Calibrations are not required when the instruments are not required to be operable. However, if calibrations are missed, they shall be performed prior to returning the instrument to an operable status.
- d. Initially once per month or according to Figure 4.1-1 with an interval of not less than one month nor more than three months. The compilation of instrument failure rate data may include data obtained

Table 4.2-2

Check, Functional Test, and Calibration Minimum Frequency for Instrumentation
Which Initiates or Controls HPCI

Ref. No. (a)	Instrument	Instrument Check Minimum Frequency	Instrument Functional Test Minimum Frequency (b)	Instrument Calibration Minimum Frequency (c)
1	Reactor Vessel Water Level (Level 2)	Once/shift	Once/month	Once/operating cycle
2	Drywell Pressure	Once/shift	Once/month	Once/operating cycle
3	HPCI Turbine Overspeed	None	N/A	Once/operating cycle
4	HPCI Turbine Exhaust Pressure	Once/shift	Once/month	Once/operating cycle
5	HPCI Pump Suction Pressure	Once/shift	Once/month	Once/operating cycle
6	Reactor Vessel Water Level (Level 8)	Once/shift	Once/month	Once/operating cycle
7	HPCI Pump Discharge Flow	Once/shift	Once/month	Once/operating cycle
8	HPCI Emergency Area Cooler Ambient Temperature	Once/shift	Once/month	Once/operating cycle
9	HPCI Steam Supply Pressure	Once/shift	Once/month	Once/operating cycle

Table 4.2-2 (Cont'd)

Ref. No. (a)	Instrument	Instrument Check Minimum Frequency	Instrument Functional Test Minimum Frequency (b)	Instrument Calibration Minimum Frequency (c)
10	HPCI Steam Line ΔP (Flow)	Once/shift	Once/month	Once/operating cycle
11	HPCI Turbine Exhaust Diaphragm Pressure	Once/shift	Once/month	Once/operating cycle
12	Suppression Chamber Area Ambient Temperature	Once/shift	Once/month	Once/operating cycle
13	Suppression Chamber Area Differential Air Temperature	Once/shift	Once/month	Once/operating cycle
14	Condensate Storage Tank Level	None	(d)	Every 3 months
15	Suppression Chamber Water Level	Once/shift	Once/month	Once/operating cycle
16	HPCI Logic Power Failure Monitor	None	Once/operating cycle	None

Notes for Table 4.2-2

- a. The column entitled "Ref. No." is only for convenience so that a one-to-one relationship can be established between items in Table 4.2-2 and items in Table 3.2-2.

Table 4.2-3

Check, Functional Test, and Calibration Minimum Frequency for Instrumentation
Which Initiates or Controls RCIC

Ref. No. (a)	Instrument	Instrument Check Minimum Frequency	Instrument Functional Test Minimum Frequency (b)	Instrument Calibration Minimum Frequency (c)
1	Reactor Vessel Water Level (Level 2)	Once/shift	Once/month	Once/operating cycle
2	RCIC Turbine Overspeed Electrical/ Mechanical	None None	N/A N/A	Once/operating cycle Once/operating cycle
3	RCIC Turbine Exhaust Pressure	Once/shift	Once/month	Once/operating cycle
4	RCIC Pump Suction Pressure	Once/shift	Once/month	Once/operating cycle
5	Reactor Vessel Water Level (Level 8)	Once/shift	Once/month	Once/operating cycle
6	RCIC Pump Discharge Flow	Once/shift	Once month	Once/operating cycle
7	RCIC Emergency Area Cooler Ambient Temperature	Once/shift	Once/month	Once/operating cycle
8	RCIC Steam Supply Pressure	Once/shift	Once/month	Once/operating cycle

Table 4.2-3 (Cont'd)

Ref. No. (a)	Instrument	Instrument Check Minimum Frequency	Instrument Functional Test Minimum Frequency (b)	Instrument Calibration Minimum Frequency (c)
9	RCIC Steam Line ΔP (Flow)	Once/shift	Once/month	Once/operating cycle
10	RCIC Turbine Exhaust Diaphragm Pressure	Once/shift	Once/month	Once/operating cycle
11	Suppression Chamber Area Ambient Temperature	Once/shift	Once/month	Once/operating cycle
12	Suppression Chamber Area Differential Air Temperature	Once/shift	Once/month	Once/operating cycle
13	RCIC Logic Power Failure Monitor	None	Once/operating cycle	None
14	Condensate Storage Tank Level	None	Monthly	Every 3 months
15	Suppression Pool Water Level	None	Monthly	Every 3 months

Notes for Table 4.2-3

- a. The column entitled "Ref. No." is only for convenience so that a one-to-one relationship can be established between items in Table 4.2-3 and items in Table 3.2-3.
- b. Instrument functional tests are not required when the instruments are not required to be operable or are tripped. However, if functional tests are missed, they shall be performed prior to returning the instrument to an operable status.

Notes for Table 4.2-3 (Cont'd)

- c. Calibrations are not required when the instruments are not required to be operable. However, if calibrations are missed, they shall be performed prior to returning the instrument to an operable status.

3-2-32

Logic system functional test and simulated automatic actuation shall be performed once each operating cycle for the following:

1. RCIC Subsystem Auto Isolation

The logic system functional tests shall include a calibration of time relays and timers necessary for proper functioning of the trip systems.

Table 4.2-4

Check, Functional Test, and Calibration Minimum Frequency for Instrumentation
Which Initiates or Controls ADS

Ref. No. (a)	Instrument	Instrument Check Minimum Frequency	Instrument Functional Test Minimum Frequency (b)	Instrument Calibration Minimum Frequency (c)
1	Reactor Vessel Water Level (Level 3)	Once/shift	Once/month	Once/operating cycle
	Reactor Vessel Water Level (Level 1)	Once/shift	Once/month	Once/operating cycle
2	Drywell Pressure	Once/shift	Once/month	Once/operating cycle
3	RHR Pump Discharge Pressure	Once/shift	Once/month	Once/operating cycle
4	CS Pump Discharge Pressure	Once/shift	Once/month	Once/operating cycle
5	Auto Depressurization Timer	None	N/A	Once/operating cycle
6	Automatic Blowdown Control Power Failure Monitor	None	Once/operating cycle	None

Notes for Table 4.2-4

- a. The column entitled "Ref. No." is only for convenience so that a one-to-one relationship can be established between items in Table 4.2-4 and items in Table 3.2-4.

Notes for Table 4.2-4 (Cont'd)

- b. Instrument functional tests are not required when the instruments are not required to be operable or are tripped. However, if functional tests are missed, they shall be performed prior to returning the instrument to an operable status.
- c. Calibrations are not required when the instruments are not required to be operable. However, if calibrations are missed, they shall be performed prior to returning the instrument to an operable status.

3.2-34

Logic system functional tests and simulated automatic actuation shall be performed once each operating cycle for the following:

1. ADS Subsystem

The logic system functional tests shall include a calibration of time relays and timers necessary for proper functioning of the trip systems.

Table 4.2-5

Check, Functional Test, and Calibration Minimum Frequency for Instrumentation
Which Initiates or Controls the LPCI Mode of RHR

Ref. No. (a)	Instrument	Instrument Check Minimum Frequency	Instrument Functional Test Minimum Frequency (b)	Instrument Calibration Minimum Frequency (c)
1	Reactor Vessel Water Level (Level 1)	Once/shift	Once/month	Once/operating cycle
2	Drywell Pressure	Once/shift	Once/month	Once/operating cycle
3	Reactor Vessel Steam Dome Pressure	Once/shift	Once/month	Once/operating cycle
4	Reactor Shroud Water Level (Level 0)	Once/shift	Once/month	Once/operating cycle
5	LPCI Cross Connect Valve Open Annunciator	None	Once/Operating cycle	None
6	RHR (LPCI) Pump Flow	Once/shift	Once/month	Once/operating cycle
7	RHR (LPCI) Pump Start Timers	None	N/A	Once/operating cycle
8	Valve Selection Timers	None	N/A	Once/operating cycle
9	RHR Relay Logic Power Failure Monitor	None	Once/operating cycle	None

Notes for Table 4.2-5

- a. The column entitled "Ref. No." is only for convenience so that a one-to-one relationship can be established between items in Table 4.2-5 and items in Table 3.2-5.
- b. Instrument functional tests are not required when the instruments are not required to be operable or are tripped. However, if functional tests are missed, they shall be performed prior to returning the instrument to an operable status.
- c. Calibrations are not required when the instruments are not required to be operable. However, if calibrations are missed, they shall be performed prior to returning the instrument to an operable status.

3.2-36

Logic system functional tests and simulated automatic actuation shall be performed once each operating cycle for the following:

1. LPCI Subsystem
2. Containment Spray Subsystem

Table 4.2-6

Check, Functional Test, and Calibration Minimum Frequency for Instrumentation
Which Initiates or Controls Core Spray

Ref. No. (a)	Instrument	Instrument Check Minimum Frequency	Instrument Functional Test Minimum Frequency (b)	Instrument Calibration Minimum Frequency (c)
1	Reactor Vessel Water Level (Level 1)	Once/shift	Once/month	Once/operating cycle
2	Drywell Pressure	Once/shift	Once/month	Once/operating cycle
3	Reactor Vessel Steam Dome Pressure	Once/shift	Once/month	Once/operating cycle
4	Core Spray Sparger Differential Pressure	Once/day	N/A	Once/operating cycle
5	CS Pump Discharge Flow	Once/shift	Once/month	Once/operating cycle
6	Core Spray Logic Power Failure Monitor	None	Once/operating cycle	None

Notes for Table 4.2-6

- a. The column entitled "Ref. No." is only for convenience so that a one-to-one relationship can be established between items in Table 4.2-6 and items in Table 3.2-6.

Notes for Table 4.2-6 (Cont'd)

- b. Instrument functional tests are not required when the instruments are not required to be operable or are tripped. However, if functional tests are missed, they shall be performed prior to returning the instrument to an operable status.
- c. Calibrations are not required when the instruments are not required to be operable. However, if calibrations are missed, they shall be performed prior to returning the instrument to an operable status.

3.2-39

Logic system functional tests and simulated automatic actuation shall be performed once each operating cycle for the following:

1. Core Spray Subsystem

The logic system functional tests shall include a calibration of time delay relays and timers necessary for proper functioning of the trip systems.

Table 4.2-11
Check and Calibration Minimum Frequency for Instrumentation
Which Provides Surveillance Information

Ref. No. (a)	Instrument	Instrument Check Minimum Frequency (b)	Instrument Calibration Minimum Frequency (c)
1	Reactor Vessel Water Level	Each shift	Once/operating cycle (f)
2	Shroud Water Level	Each shift	Once/operating cycle (f)
3	Reactor Pressure	Each shift	Once/operating cycle (f)
4	Drywell Pressure	Each shift	Every 6 months
5	Drywell Temperature	Each shift	Every 6 months
6	Suppression Chamber Air Temperature	Each shift	Every 6 months
7	Suppression Chamber Water Temperature	Each shift	Every 6 months
8	Suppression Chamber Water Level	Each shift	Every 6 months
9	Suppression Chamber Pressure	Each shift	Every 6 months
10	Rod Position Information System (RPIS)	Each shift	N/A
11	Hydrogen and Oxygen Analyzer	Each shift	Every 6 months
12	Post LOCA Radiation	Each shift	Every 6 months
13	a) Safety/Relief Valve Position Pri- mary Indicator	Monthly	Every 18 months
	b) Safety/Relief Valve Position Secondary Indicator	Monthly	Every 18 months

Notes for Table 4.2-11

PLANT HATCH UNIT 1

3.2-49

- a. The column entitled "Ref No." is only for convenience so that a one-to-one relationship can be established between items in Table 4.2-11 and items in Table 3.2-11.
- b. Instrument checks are not required when the instruments are not required to be operable or are tripped. However, if instrument checks are missed, they shall be performed prior to returning the instrument to an operable status.
- c. Calibrations are not required when the instruments are not required to be operable or are tripped. However, if calibrations are missed, they shall be performed prior to returning the instrument to an operable status.
- d. Functional tests are not required when the instruments are not required to be operable or are tripped. However, if functional tests are missed, they shall be performed prior to returning the instrument to an operable status.
- e. Calibration of a drywell high range monitor shall consist of an electronic calibration of the channel, not including the detector, for range decades above 10 R/hr and one point calibration check of the detector below 10 R/hr with an installed or portable gamma source.
- f. The entire loop shall be calibrated once per 18 months; however, the recorder itself must be calibrated at least once per 12 months.

3.2 PROTECTIVE INSTRUMENTATION

In addition to the Reactor Protection System (RPS) instrumentation which initiates a reactor scram, protective instrumentation has been provided which initiates action to mitigate the consequences of accidents which are beyond the operators ability to control, or terminates operator errors before they result in serious consequences. This set of Specifications provides the limiting conditions for operation of the instrumentation:

(a) which initiates reactor vessel and primary containment isolation, (b) which initiates or controls the core and containment cooling systems, (c) which initiates control rod blocks, (d) which initiates protective action, (e) which monitors leakage into the drywell and (f) which provides surveillance information. The objectives of these specifications are (i) to assure the effectiveness of the protective instrumentation when required by preserving its capability to tolerate a single failure of any component of such systems even during periods when portions of such systems are out of service for maintenance, and (ii) to prescribe the trip settings required to assure adequate performance. When necessary, one channel may be made inoperable for brief intervals to conduct required functional tests and calibrations.

A. Instrumentation Which Initiates Reactor Vessel and Primary Containment Isolation (Table 3.2-1)

Isolation valves are installed in those lines which penetrate the primary containment and must be isolated during a loss of coolant accident so that the radiation dose limits are not exceeded during an accident condition. Actuation of these valves is initiated by protective instrumentation shown in Table 3.2-1 which senses the conditions for which isolation is required. Such instrumentation must be available whenever primary containment integrity is required. The objective is to isolate the primary containment so that the guidelines of 10 CFR 100 are not exceeded during an accident. The events when isolation is required are discussed in Appendix G of the FSAR. The instrumentation which initiates primary system isolation is connected in a dual bus arrangement.

1. Reactor Vessel Water Level

a. Reactor Vessel Water Level Low (Level 3) (Narrow Range)

The reactor water level instrumentation is set to trip when reactor water level is approximately 14 feet above the top of the active fuel. This level is referred to as Level 3 in the Technical Specifications and corresponds to a reading of 10.0 inches on the Narrow Range Scale. This trip initiates Group 2 and 6 isolation but does not trip the recirculation pumps.

b. Reactor Vessel Water Level Low Low (Level 2)

The reactor water level instrumentation is set to trip when reactor water level is approximately 9 feet above the top of the active fuel. This level is referred to as Level 2 in the Technical Specifications and corresponds to a reading of -47 inches. This trip initiates Group 5 isolation, starts the standby gas treatment system, and initiates secondary containment isolation.

BASES FOR LIMITING CONDITIONS FOR OPERATION

3.2.A.1.c. Reactor Vessel Water Level Low Low Low (Level 1)

The reactor water level instrumentation is set to trip when the reactor water level is approximately 51 inches above the top of the active fuel. This level is referred to as Level 1 in the Technical Specifications and corresponds to a reading of -113 inches. This trip initiates Group 1 isolation.

3.2.A.2. Reactor Vessel Steam Dome Pressure (Shutdown Cooling Mode) Low Permissive

This setpoint is chosen to preserve the pressure integrity of the RHR system under conditions of increasing reactor pressure (startup). The RHR suction valves from the reactor (shutdown cooling mode) would be closed when the 145 psig setpoint is reached. This function protects against RHR system pipe breaks during the shutdown cooling mode of operation. Additionally, at reactor pressures below this setpoint the primary containment isolation signals are permitted to close the in-board motor operated injection valve (LPCI mode).

3. Drywell Pressure High

The Bases for Drywell Pressure High are discussed in the Bases for Specification 3.1.A.5. Pressure above the trip setting starts the SGTS and initiates primary and secondary containment isolation.

4. Main Steam Line Radiation High

Radiation monitors in the main steam line tunnel have been provided to detect gross fuel failure as in the control rod drop accident. This instrumentation causes a Group 1 isolation. With the established setting of approximately three times normal full power background, fission product release is limited so that 10 CFR 100 guidelines are not exceeded for this accident. Ref. Section 14.4.4 FSAR.

5. Main Steam Line Pressure Low

The Bases for Main Steam Line Pressure Low are discussed in the Bases for Specification 2.1.A.6.

6. Main Steam Line Flow High

Venturis are provided in the main steam lines as a means of measuring steam flow and also limiting the loss of mass inventory from the vessel during a steam line break accident. In addition to monitoring steam flow, instrumentation is provided which initiates Group 1 isolation. The primary function of the instrumentation is to detect a break in the main steam line. For the worst case accident, a main steam line break outside the drywell, the trip setting of 115 psid, corresponding to 138% of rated steam flow, in conjunction with the flow limiters and main steam isolation valve closure, limits the mass inventory loss such that fuel is not uncovered. Fuel temperatures remain approximately 1000°F and release of radioactivity to the environs is well below 10 CFR 100 guidelines. Ref. Section 14.6.5 of the FSAR.

7. Main Steam Line Tunnel Temperature High

Temperature monitoring instrumentation is provided in the main steam line tunnel to detect leaks in this area. Trips are provided on this instrumentation and when exceeded cause a Group 1 isolation. Its setting is low enough to detect leaks of the order of five to 10 gpm; thus, it is capable of covering the entire spectrum of breaks. For large breaks, it is a back-up to high steam flow instrumentation discussed above, and for small breaks

3.2.A.7 Main Steam Line Tunnel Temperature High (Continued)

with the resultant small release of radioactivity, gives isolation before the guidelines of 10 CFR 100 are exceeded.

8. Reactor Water Cleanup System Differential Flow High

Gross leakage (pipe break) from the reactor water cleanup system is detected by measuring the difference of flow entering and leaving the system. The set point is low enough to ensure prompt isolation of the cleanup system in the event of such a break but, not so low that spurious isolation can occur due to normal system flow fluctuations and instrument noise. Time delay relays are used to prevent the isolation signal which might be generated from the initial flow surge when the cleanup system is started or when operational system adjustments are made which produce short term transients.

9. Reactor Water Cleanup Area Temperature High and

10. Reactor Water Cleanup Area Ventilation Differential Temperature High

Leakage in the high temperature process flow of the reactor water cleanup system external to the primary containment will be detected by temperature sensing elements. Temperature sensors are located in the inlet and outlet ventilation ducts to measure the temperature difference. Local ambient temperature sensors are located in the compartment containing equipment and piping for this system. An alarm in the main control room will be set to annunciate a temperature rise corresponding to a leakage within the identified limit. In addition to annunciation, a high cleanup room temperature will actuate automatic isolation of the cleanup system.

11. Condenser Vacuum Low

The Bases for Condenser Vacuum Low are discussed in The Bases for Specification 2.1.A.7.

B. Instrumentation Which Initiates or Controls HPCI (Table 3.2-2)

1. Reactor Vessel Water Level Low Low (Level 2)

The reactor vessel water level instrumentation setpoint which initiates HPCI is ≥ -47 inches. This level is approximately 9 feet above the top of the active fuel and in the Technical Specifications is referred to as Level 2. The reactor vessel low water level setting for HPCI system initiation is selected high enough above the active fuel to start the HPCI system in time both to prevent excessive fuel clad temperatures and to prevent more than a small fraction of the core from reaching the temperature at which gross fuel failure occurs. The water level setting is far enough below normal levels that spurious HPCI system startups are avoided.

2. Drywell Pressure High

The drywell pressure which initiates HPCI is ≤ 2 psig. High drywell pressure could indicate a failure of the nuclear system process barrier. This pressure is selected to be as low as possible without inducing spurious HPCI system startups. This instrumentation serves as a backup to the water level instrumentation described above.

3.2.B.3 HPCI Turbine Overspeed

The HPCI turbine is automatically shut down by tripping the HPCI turbine stop valve closed when the 5000 rpm setpoint on the mechanical governor is reached. A turbine overspeed trip is required to protect the physical integrity of the turbine.

4. HPCI Turbine Exhaust Pressure High

When HPCI turbine exhaust pressure reaches the setpoint (≤ 146 psig) the HPCI turbine is automatically shut down by tripping the HPCI stop valve closed. HPCI turbine exhaust high pressure is indicative of a condition which threatens the physical integrity of the exhaust line.

5. HPCI Pump Suction Pressure Low

A pressure switch is used to detect low HPCI system pump suction pressure and is set to trip the HPCI turbine at ≤ 12.6 inches of mercury vacuum. This setpoint is chosen to prevent pump damage by cavitation.

6. Reactor Vessel Water Level High (Level 8)

A reactor water level of +56.5 inches is indicative that the HPCI system has performed satisfactorily in providing makeup water to the reactor vessel. The reactor vessel high water level setting which trips the HPCI turbine is near the top of the steam separators and is sufficient to prevent gross moisture carryover to the HPCI turbine. Two analog differential pressure transmitters trip to initiate a HPCI turbine shutdown.

7. HPCI Pump Discharge Flow High

To prevent damage by overheating at reduced HPCI system pump flow, a pump discharge minimum flow bypass is provided. The bypass is controlled by an automatic, D. C. motor-operated valve. A high flow signal from a flow meter downstream of the pump on the main HPCI line will cause the bypass valve to close. Two signals are required to open the valve: A HPCI pump discharge pressure transmitter high differential pressure signal must be received to act as a permissive to open the bypass valve in the presence of a low flow signal from the differential pressure transmitter.

NOTE:

Because the steam supply line to the HPCI turbine is part of the nuclear system process barrier, the following conditions (8-13) automatically isolate this line, causing shutdown of the HPCI system turbine.

8. HPCI Emergency Area Cooler Ambient Temperature High

High ambient temperature in the HPCI equipment room near the emergency area cooler could indicate a break in the HPCI system turbine steam line. The automatic closure of the HPCI steam line valves prevents the excessive loss of reactor coolant and the release of significant amounts of radioactive material from the nuclear system process barrier. The high

3.2.B.8 HPCI Emergency Area Cooler Ambient Temperature High (Continued)

temperature setting of $\leq 169^{\circ}\text{F}$ was selected to be far enough above anticipated normal HPCI system operational levels to avoid spurious isolation but low enough to provide timely detection of HPCI turbine steam line break.

9. HPCI Steam Supply Pressure Low

Low pressure in the HPCI steam line could indicate a break in the HPCI steam line. Therefore, the HPCI steam line isolation valves are automatically closed. The steam line low pressure function is provided so in the event that a gross rupture of the HPCI steam line occurred upstream from the high flow sensing location, thus negating the high flow indicating function, isolation would be effected on low pressure. The allowable value of ≥ 100 psig is selected at a pressure sufficiently high enough to prevent turbine stall.

10. HPCI Steam Line ΔP (Flow) High

HPCI steam line high flow could indicate a break in the HPCI turbine steam line. The automatic closure of the HPCI steam line isolation valves prevents the excessive loss of reactor coolant and the release of significant amount of radioactive materials from the nuclear system process barrier. Upon detection of HPCI steam line high flow the HPCI turbine steam line is isolated. The high steam flow trip setting of 303% flow was selected high enough to avoid spurious isolation, i.e., above the high steam flow rate encountered during turbine starts. The setting was selected low enough to provide timely detection of an HPCI turbine steam line break.

11. HPCI Turbine Exhaust Diaphragm Pressure High

High pressure in the HPCI turbine exhaust could indicate that the turbine rotor is not turning, thus allowing reactor pressure to act on the turbine exhaust line. The HPCI steam line isolation valves are automatically closed to prevent overpressurization of the turbine exhaust line. The turbine exhaust diaphragm pressure trip setting of ≤ 20 psig is selected high enough to avoid isolation of the HPCI if the turbine is operating, yet low enough to effect isolation before the turbine exhaust line is unduly pressurized.

12. Suppression Chamber Area Ambient Temperature High

A temperature of 169°F will initiate a timer to isolate the HPCI turbine steam line.

3.2.B.13 Suppression Chamber Area Differential Air Temperature High

A differential air temperature greater than the trip setting of $\leq 42^{\circ}\text{F}$ between the inlet and outlet ducts which ventilate the suppression chamber area will initiate a timer to isolate the HPCI turbine steam line.

14. Condensate Storage Tank Level Low

The CST is the preferred source of suction for HPCI. In order to provide an adequate water supply, an indication of low level in the CST automatically switches the suction to the suppression chamber. A trip setting of 0 inches corresponds to 10,000 gallons of water remaining in the tank.

15. Suppression Chamber Water Level High

A high water level in the suppression chamber automatically switches HPCI suction to the suppression chamber from the CST.

16. HPCI Logic Power Failure Monitor

The HPCI Logic Power Failure Monitor monitors the availability of power to the logic system. In the event of loss of availability of power to the logic system, an alarm is annunciated in the control room.

C. Instrumentation Which Initiates or Controls RCIC (Table 3.2-3)

1. Reactor Vessel Water Level Low Low (Level 2)

The reactor vessel water level instrumentation setpoint which initiates RCIC is ≥ 47 inches. This level is approximately 9 feet above the top of the active fuel and is referred to as Level 2. This setpoint insures that RCIC is started in time to preclude conditions which lead to inadequate core cooling.

2. RCIC Turbine Overspeed

The RCIC turbine is automatically shutdown by tripping the RCIC turbine stop valve closed when the 125% speed at rated flow setpoint on the mechanical governor is reached. Turbine overspeed is indicative of a condition which threatens the physical integrity of the system. An electrical tachometer trip setpoint of 110% also will trip the RCIC turbine stop valve closed.

3. RCIC Turbine Exhaust Pressure High

When RCIC turbine exhaust pressure reaches the setpoint (≤ 45 psig), the RCIC turbine is automatically shut down by tripping the RCIC turbine stop valve closed. RCIC turbine exhaust high pressure is indicative of a condition which threatens the physical integrity of the exhaust line.

4. RCIC Pump Suction Pressure Low

One differential pressure transmitter is used to detect low RCIC system pump suction pressure and is set to trip the RCIC turbine at ≤ 12.6 inches of mercury vacuum.

3.2.C.5 Reactor Vessel Water Level High (Level 8)

A high reactor water level trip is indicative that the RCIC system has performed satisfactorily in providing makeup water to the reactor vessel. The reactor vessel high water level setting which trips the RCIC turbine is near the top of the steam separators and sufficiently low to prevent gross moisture carryover to the RCIC turbine. Two differential pressure transmitters trip to initiate a RCIC turbine shutdown. Once tripped the system is capable of automatic reset after the water level drops below Level 8. This automatic reset eliminates the need for manual reset of the system before the operator can take manual control to avoid fluctuating water levels.

6. RCIC Pump Discharge Flow

To prevent damage by overheating at reduced RCIC system pump flow, a pump discharge minimum flow bypass is provided. The bypass is controlled by an automatic, D. C. motor-operated valve. A high flow signal from a flow meter downstream of the pump on the main RCIC line will cause the bypass valve to close. Two signals are required to open the valve: A RCIC pump discharge pressure transmitter high differential pressure signal must be received to act as a permissive to open the bypass valve in the presence of a low flow signal from the differential pressure transmitter.

Note:

Because the steam supply line to the RCIC turbine is part of the nuclear system process barrier, the following conditions (7 - 13) automatically isolate this line, causing shutdown of the RCIC system turbine.

7. RCIC Emergency Area Cooler Ambient Temperature High

High ambient temperature in the RCIC equipment room near the emergency area cooler could indicate a break in the RCIC system turbine steam line. The automatic closure of the RCIC steam line valves prevents the excessive loss of reactor coolant and the release of significant amounts of radioactive material from the nuclear system process barrier. The high temperature setting of $\leq 169^{\circ}\text{F}$ was selected to be far enough above anticipated normal RCIC system operational levels to avoid spurious isolation but low enough to provide timely detection of a RCIC turbine steam line break.

8. RCIC Steam Supply Pressure Low

Low pressure in the RCIC steam supply could indicate a break in the RCIC steam line. Therefore, the RCIC steam supply isolation valves are automatically closed. The steam line low pressure function is provided so that in the event a gross rupture of the RCIC steam line occurred upstream from the high flow sensing location, thus negating the high flow indicating function, isolation would be effected on low pressure. The isolation setpoint of ≥ 60 psig is chosen at a pressure below that at which the RCIC turbine can effectively operate.

3.2.C.9 RCIC Steam Line (ΔP) Flow High

RCIC turbine high steam flow could indicate a break in the RCIC turbine steam line. The automatic closure of the RCIC steam line isolation valves prevents the excessive loss of reactor coolant and the release of significant amounts of radioactive materials from the nuclear system process barrier. Upon detection of RCIC turbine high steam flow the RCIC turbine steam line is isolated. The high steam flow trip setting of 306% flow was selected high enough to avoid spurious isolation, i.e., above the high steam flow rate encountered during turbine starts. The setting was selected low enough to provide timely detection of a RCIC turbine steam line break.

10. RCIC Turbine Exhaust Diaphragm Pressure High

High pressure in the RCIC turbine exhaust could indicate that the turbine rotor is not turning, thus allowing reactor pressure to act on the turbine exhaust line. The RCIC steam line isolation valves are automatically closed to prevent overpressurization of the turbine exhaust line. The turbine exhaust diaphragm pressure trip setting of ≤ 20 psig is selected high enough to avoid isolation of the RCIC if the turbine is operating, yet low enough to effect isolation before the turbine exhaust line is unduly pressurized.

11. Suppression Chamber Area Ambient Temperature High

As in the RCIC equipment room, and for the same reason, a temperature of $\leq 169^{\circ}\text{F}$ will initiate a timer to isolate the RCIC turbine steam line.

12. Suppression Chamber Area Differential Air Temperature High

A high differential air temperature between the inlet and outlet ducts which ventilate the suppression chamber area will initiate a timer to isolate the RCIC turbine steam line.

13. RCIC Logic Power Failure Monitor

The RCIC Logic Power Failure Monitor monitors the availability of power to the logic system. In the event of loss of availability of power to the logic system, an alarm is annunciated in the control room.

14. Condensate Storage Tank Level Low

The low CST level signal transfers RCIC suction from the CST to the suppression pool. The setpoint was chosen to ensure an uninterrupted supply of water during suction transfer.

15. Suppression Pool Water Level High

A high water level in the suppression chamber automatically switches RCIC suction from the CST to the suppression pool.

D. Instrumentation Which Initiates or Controls ADS (Table 3.2-4)

The ADS is a backup system to HPCI. In the event of failure by HPCI to maintain reactor water level, ADS will initiate depressurization of the reactor in time for LPCI and CS to adequately cool the core. Four signals are required to initiate ADS: Low water level, confirmed low water level, high drywell pressure, and either a RHR or Core Spray pump available. The simultaneous presence of these four signals will initiate a 120 second timer which will depressurize the reactor if not reset.

1. Reactor Vessel Water Level

a. Reactor Vessel Water Level Low (Level 3)

The second reactor vessel low water level initiation setting (+10.0 inches) is selected to confirm that water level in the vessel is in fact low, thus providing protection against inadvertent depressurization in the event of an instrument line (water level) failure. Such a failure could produce a simultaneous high drywell pressure. A confirmed low level is one of four signals required to initiate ADS.

b. Reactor Vessel Water Level Low Low Low (Level 1)

The reactor vessel low water level setting of -113 inches is selected to provide a permissive signal to open the relief valve and depressurize the reactor vessel in time to allow adequate cooling of the fuel by the core spray and LPCI systems following a LOCA in which the other make up systems (RCIC and HPCI) fail to maintain vessel water level. This signal is one of four required to initiate ADS.

2. Drywell Pressure High

A primary containment high pressure of ≥ 2 psig indicates that a breach of the nuclear system process barrier has occurred inside the drywell. The signal is one of four required to initiate the ADS.

3.2.D. 3. RHR Pump Discharge Pressure High

An RHR pump discharge pressure of ≥ 112 psig indicates that LPCI flow is available when the reactor is depressurized. The presence of this signal means low pressure core standby cooling is available. Low pressure core standby cooling available is one of the four signals required to initiate ADS.

4. Core Spray Pump Discharge Pressure High

A core spray pump discharge pressure of ≥ 137 psig indicates that Core Spray flow is available when the reactor is depressurized. The presence of this signal means low pressure core standby cooling is available. Low pressure core standby cooling available is one of the four signals required to initiate ADS.

5. Auto Depressurization Timer

The 120-second delay time setting is chosen to be long enough so that the HPCI system has time to start, yet not so long that the core spray system and LPCI are unable to adequately cool the core if HPCI fails to start. An alarm in the main control room is annunciated each time either of the timers is timing. Resetting the automatic depressurization system logic in the presence of tripped initiating signals recycles the timers.

6. Automatic Blowdown Control Power Failure Monitor

The Automatic Blowdown Control Power Failure Monitor monitors the availability of power to the logic system. In the event of loss of availability of power to the logic system, an alarm is annunciated in the control room.

E. Instrumentation Which Initiates or Controls the LPCI Mode of RHR (Table 3.2-5)1. Reactor Vessel Water Level Low Low Low (Level 1)

Reactor vessel low water level (Level 1) initiates LPCI and indicates that the core is in danger of being overheated because of an insufficient coolant inventory. This level is sufficient to allow the timed initiation of the various valve closure and loop selection routines to go to completion and still successfully perform its design function.

2. Drywell Pressure High

Primary containment high pressure could indicate a break in the nuclear system process barrier inside the drywell. The high drywell pressure setpoint is selected to be high enough to avoid spurious starts but low enough to allow timely system initiation.

3. Reactor Vessel Steam Dome Pressure Low

The Bases for Reactor Pressure (Shutdown Cooling Mode) are discussed in the Bases for Specification 3.2.A.2.

With an analytical limit of ≥ 300 psig and a nominal trip setpoint of 370 psig, the recirculation discharge valve will close successfully during a LOCA condition.

Once the LPCI system is initiated, a reactor low pressure setpoint of 460 psig produces a signal which is used as a permissive to open the LPCI injection valves. The valves do not open, however, until reactor pressure falls below the discharge head of LPCI.

3.2.E.4 Reactor Shroud Water Level Low (Level 0)

A reactor water level \geq -202 inches below instrument zero is indicative that LPCI has made progress in reflooding the core. A simultaneous high drywell pressure trip indicates the need for containment cooling. The \geq -202 inch setpoint acts as a permissive for manual diversion for some of the LPCI flow to containment spray.

5. LPCI Cross Connect Valve Open Annunciator

With the modified LPCI arrangement, the cross connect valve status was changed from normally open to normally closed. Inadvertent opening of this valve could negate the LPCI system injection when needed. The annunciator will alarm when the LPCI cross connect valve is not fully closed.

6. RHR (LPCI) Pump Flow Low

A flow element and differential pressure transmitter are provided downstream of each pair of RHR pumps in their common line. To protect the pumps from overheating at low flow rates, a minimum flow bypass with a restricting orifice is provided for each pump which routes water through the common motor-operated valve to the suppression chamber. This minimum flow bypass valve automatically opens upon sensing low flow in the common discharge piping. The valve automatically closes whenever the flow (whether from both pumps or a single pump) is above the low flow setting.

7. RHR (LPCI) Pump Start Timers

If normal AC power is available, four pumps automatically start without delay. If normal AC power is not available one pump starts without delay as soon as power becomes available from the standby sources. The other three pumps start after a 10-second delay. The timer provides correct sequencing of the loads to the diesel generator.

3.2.E.8 Valve Selection Timers

After 10 minutes, a timer cancels the LPCI signals to the injection valves. The cancellation of the signals allows the operator to divert the water for other post-accident purposes. Cancellation of the signals does not cause the injection valves to move.

9. RHR Relay Logic Power Failure Monitor

The RHR Relay Logic Power Failure Monitor monitors the availability of power to the logic system. In the event of loss of availability of power to the logic system, an alarm is annunciated in the control room.

F. Instrumentation Which Initiates or Controls Core Spray (Table 3.2-6)

1. Reactor Vessel Water Level Low Low Low (Level 1)

A reactor low water level of -113 inches (level 1) initiates Core Spray. This level is indicative that the core is in danger of being overheated because of an insufficient coolant inventory.

2. Drywell Pressure High

Primary containment high pressure is indicative of a break in the nuclear system process barrier inside the drywell. The high drywell pressure setpoint of ≤ 2 psig is selected to be high enough to avoid spurious system initiation but low enough to allow timely system initiation.

3. Reactor Vessel Steam Dome Pressure Low

Once the core spray system is initiated, a reactor low pressure setpoint of 460 psig produces a signal which is used as a permissive to open the core spray injection valves. The valves do not open, however, until reactor pressure falls below the discharge head of the core spray system.

4. Core Spray Sparger Differential Pressure

A detection system is provided to continuously confirm the integrity of the core spray piping between the inside of the reactor vessel and the core shroud. A differential pressure switch measures the pressure difference between the top of the core support plate and the inside of the core spray sparger pipe just outside the reactor vessel. If the core spray sparger piping is sound, this pressure difference will be the pressure drop across the core resulting from inter-channel leakage. If integrity is lost, this pressure drop will include the steam separator pressure drop. An increase in the normal pressure drop initiates an alarm in the main control room.

3.2.F.5. Core Spray Pump Discharge Flow

A differential pressure transmitter is provided downstream of each core spray pump to indicate the condition of each pump. To protect the pumps from overheating at low flow rates a minimum flow bypass line, which routes water from the pump discharge to the suppression chamber, is provided. A single motor-operated valve controls the condition of each bypass line. The minimum flow bypass valve automatically opens upon sensing low flow in the discharge line. The valve automatically closes whenever the flow is above the low flow setting.

6. Core Spray Logic Power Failure Monitor

The Core Spray Logic Power Failure Monitor monitors the availability of power to the logic system. In the event of loss of availability of power to the logic system, an alarm is annunciated in the control room.

G. Neutron Monitoring Instrumentation Which Initiates Control Rod Blocks (Table 3.2-7)

These control rod block functions are provided to prevent excessive control rod withdrawal so that MCPR does not decrease to 1.07. The trip logic for this function is 1 out of n: e.g., any trip on one of six APRM's, eight IRM's or four SRM's will result in a rod block.

The minimum instrument channel requirements assure sufficient instrumentation to assure that the single failure criteria is met.

1. SRM

a. Inoperative

This rod block assures that no control rod is withdrawn during low neutron flux level operations unless proper neutron monitoring capability is available, in that all SRM channels are in service or properly bypassed.

b. Not Fully Inserted

Any source range monitor not fully inserted into the core when the SRM count rate level is below the retract permit level will cause a rod block. This assures that no control rod is withdrawn unless all SRM detectors are properly inserted when they must be relied upon to provide the operator with a knowledge of the neutron flux level.

c. Downscale

This rod block assures that no control rod is withdrawn unless the SRM count rate is above the minimum prescribed for low neutron flux level monitoring.

Table 3.7-1
(Concluded)

Primary Containment Isolation Valves

These notes refer to the lower case letters in parentheses on the previous page.
NOTES:

a. Key: O = Open SC = Stays closed
 C = Closed GC = Goes closed

b. Isolation Groupings are as follows:

GROUP 1: The valves in Group 1 are actuated by any one of the following conditions:

1. Reactor vessel water level Low Low Low (Level 1)
2. Main steam line radiation high
3. Main steam line flow high
4. Main steam line tunnel temperature high
5. Main steam line pressure low
6. Condenser vacuum low

GROUP 2: The valves in Group 2 are actuated by one one of the following conditions:

1. Reactor vessel water level low (Level 3)
2. Drywell pressure high

GROUP 3: Isolation valves in the high pressure coolant injection (HPCI) system are actuated by any one of the following conditions:

1. HPCI steam line flow high
2. High temperature in the vicinity of the HPCI steam line
3. HPCI steam supply pressure low
4. HPCI turbine exhaust diaphragm pressure

GROUP 4: Primary Containment Isolation valves in the reactor core isolation cooling (RCIC) system are actuated by any one of the following conditions:

1. RCIC steam line flow high
2. High temperature in the vicinity of the RCIC steam line
3. RCIC steam supply pressure low

GROUP 5: The valves in Group 5 are actuated by any one of the following conditions:

1. Reactor vessel water level Low Low (Level 2)
2. Reactor water cleanup area temperature high
3. Reactor water cleanup area ventilation differential temperature high
4. Reactor water cleanup system differential flow high
5. Actuation of Standby Liquid Control System - closes outside valve only
6. High temperature following non-regenerative heat exchanger - closes outside valve only

GROUP 6: The valves in Group 6 are actuated by the following conditions:

1. Reactor vessel water level low (Level 3)
2. Reactor vessel steam dome pressure low permissive

c. Requires a Group 2 signal or a Reactor Building ventilation high radiation isolation signal.

d. For redundant lines, only one set of valves is listed. Other sets are identical except for valve numbers, which are included. Valve numbers are listed in order from within primary containment outward for each line.

e. Not applicable to check valves.

APPENDIX 1

SIGNIFICANT
HAZARDS REVIEW

Overview of the Individual 10 CFR 50.92 Evaluations of the Proposed ATTS-Related Technical Specifications Changes for the Edwin I. Hatch Nuclear Plant-Unit 1

The proposed Technical Specifications changes, which Georgia Power Company (GPC) is proposing for use with the new analog transmitter trip system (ATTS) currently being installed at Hatch 1, include new instrument trip setpoints/allowable values and surveillance intervals which take credit for the advantages that the new devices have over those currently installed at the plant, in terms of setpoint drift and instrument accuracy. In addition to these types of revisions, this submittal also proposes a number of other types of Technical Specifications changes including the following:

- Changes which account for modifications to instrument loops or trip logic resulting from the new ATTS design.
- Changes which correct minor typographical or descriptive errors found in the Hatch 1 Technical Specifications during the safety review process for ATTS. (The errors found do not necessarily affect sections covering requirements for ATTS components.)
- Changes to the Technical Specifications Bases sections which correct existing errors and update them with respect to the other proposed ATTS changes.

All of these proposed modifications were based on Nuclear Regulatory Commission (NRC) and industry standards listed in Table A1-1 of this appendix, to the extent practicable. It should be noted that use of several documents in Table A1-1 goes beyond the extent of commitments made by GPC, including those made in the Hatch 1 FSAR, and that their use in the design and implementation of ATTS does not represent an extension by GPC of these commitments to other plant systems designed to other criteria. If conflicts arose between the requirements of the FSAR and those contained in the listed standards, the requirements of Hatch 1 FSAR section 7.1 and Appendix F were followed by GPC.

The individual 10 CFR 50.92 evaluations contained in the following pages, when taken collectively, provide a complete evaluation for significant hazards resulting from all proposed ATTS-related license changes. Based on the conclusion of each of the individual reviews, which was that each type or group of changes did not result in a significant hazard as defined in 10 CFR 50.92, GPC has determined that the same conclusion is valid for this entire license change proposal.

TABLE A1-1

ANALOG TRANSMITTER TRIP SYSTEM CONFORMANCE CRITERIA (SHEET 1 OF 3)

IEEE Standards

IEEE-279-1971: Criteria for Protection System for Nuclear Power Generating Station

IEEE-323-1974: Qualifying Class 1E Equipment for Nuclear-Power Generating Stations

IEEE-336-1977: Installation, Inspection and Testing Requirements for Instrumentation and Electrical Equipment During the Construction of Nuclear Power Generating Stations

IEEE-338-1977: Criteria for Periodic Testing of Nuclear Power Generating Station Safety Systems

IEEE-344-1975: Recommended Practices for Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations

IEEE-397-1977: Application of the Single-Failure Criterion to Nuclear Power Generating Station Class 1E Systems

IEEE-420-1973: Trial-Use Guide for Class 1E Control Switchboards for Nuclear Power Generating Stations

IEEE-494-1974: Method for Identification of Documents Related to Class 1E Equipment and Systems for Nuclear Power Generating Stations

NRC Regulatory Guides

Regulatory Guide 1.22: Periodic Testing of Protection System Actuation Functions

Regulatory Guide 1.28: Quality Assurance Program Requirements

Regulatory Guide 1.29: Seismic Design Classification

Regulatory Guide 1.30: Quality Assurance Requirements for the Installation, Inspection, and Testing of Instrumentation and Electrical Equipment

Regulatory Guide 1.38: Quality Assurance Requirements for Packing, Shipping, Receiving, Storage, and Handling of Items for Water-Cooled Nuclear Power Plants

Regulatory Guide 1.47: Bypassed and Inoperable Status Indication for Nuclear Power Plant Safety Systems

TABLE A1-1 (SHEET 2 OF 3)

NRC Regulatory Guides (continued)

Regulatory Guide 1.53: Application of the Single-Failure Criterion to Nuclear Power Plant Protection Systems

Regulatory Guide 1.61: Damping Value for Seismic Design of Nuclear Power Plants

Regulatory Guide 1.62: Manual Initiation of Protective Actions

Regulatory Guide 1.64: Quality Assurance Requirements for the Design of Nuclear Power Plants

Regulatory Guide 1.68: Initial Test Program for Water-Cooled Reactor Power Plants

Regulatory Guide 1.75: Physical Independence of Electrical Systems

Regulatory Guide 1.89: Qualification of Class 1E Equipment for Nuclear Power Plants

Regulatory Guide 1.92: Combining Modal Responses and Spatial Components in Seismic Response Analysis

Regulatory Guide 1.97: Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant Conditions During and Following an Accident

Regulatory Guide 1.100: Seismic Qualification of Electric Equipment for Nuclear Power Plants

Regulatory Guide 1.131: Qualification Tests of Electric Cables, Field Splices, and Connections for Light-Water-Cooled Nuclear Power Plants

NRC Regulations

Regulation 10 CFR 21: Reporting of Defects and Noncompliance

Regulation 10 CFR 50.49: Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants

Regulation 10 CFR 50.55a: Issuance, Limitation and Conditions of Licenses and Construction Permits (CP) - Codes and Standards

Regulation 10 CFR 50, Appendix A: General Design Criteria (GDC) for Nuclear Power Plants

TABLE A1-1 (SHEET 3 OF 3)

General Design Criteria

- GDC 1: Quality Standards and Records
- GDC 2: Design Basis for Protection Against Natural Phenomena
- GDC 5: Sharing of Structures, Systems, and Components
- GDC 10: Reactor Design
- GDC 13: Instrumentation and Control
- GDC 20: Protection System Functions
- GDC 21: Protection System Reliability and Testability
- GDC 22: Protection System Independence
- GDC 23: Protection System Failure Mode
- GDC 24: Separation of Protection and Control Systems
- GDC 29: Protection Against Anticipated Operational Occurrences

10 CFR 50.92 Evaluation for the Proposed Changes to the Technical Specifications Surveillance Requirements as a Result of the Installation of the Analog Transmitter Trip System for Edwin I. Hatch Nuclear Plant-Unit 1^(a)

Georgia Power Company (GPC) reviewed the requirements of 10 CFR 50.92 as they relate to the proposed Technical Specification changes due to the installation of the analog transmitter trip system (ATTS). ATTS replaces the pressure, level, and temperature switches in the reactor protection system and the emergency core cooling system (ECCS) with analog sensor/trip unit combinations. The system is designed to improve sensor intelligence and reliability, while still providing continued monitoring of critical parameters and performing the intended basic logic function. Since the ATTS instrumentation is superior in design to the mechanical switches currently used at Plant Hatch, certain surveillance intervals may be extended without any significant effect on the expected magnitude of sensor drift or frequency of instrument malfunction. GPC proposes to change the surveillance requirements for the ATTS instrumentation to once per shift for channel checks, once per month for channel functional tests, and once per operating cycle for channel calibrations. These proposed surveillance requirements were previously approved on a generic bases for ATTS equipment by the Nuclear Regulatory Commission (NRC) review of the General Electric Company topical report NEDO 21617-A. These standardized interval changes for ATTS were also approved for specific use at Plant Hatch in License Amendments 33 and 39 for Unit 2 and 103 and 104 for Unit 1. Additional changes to the nomenclature used in the Technical Specifications are included for clarification and consistency with this proposed change.

GPC reviewed the proposed changes and considers them not to involve a significant hazards consideration for the following reasons:

1. They would not significantly increase the probability or consequences of an accident previously evaluated, because the new ATTS instruments have been demonstrated to be superior in design to the existing devices in terms of instrument inaccuracy and drift characteristics. In addition, the new setpoints have been rigorously calculated, assuming the proposed surveillance frequencies.
2. They would not create the possibility of a new or different accident from any accident previously evaluated, because the new surveillance intervals for ATTS were developed to be consistent with the Plant Hatch-Unit 1 Final Safety Analysis Report (FSAR) descriptions.
3. They would not involve a significant reduction in a margin of safety, because the new surveillance requirements are tailored to the ATTS instruments, using the methodology of Regulatory Guide 1.105. In addition, the bases for the margins of safety, as described in the FSAR, have been maintained.

a. See section 3B (page 3-3) for discussion of proposed revisions.

10 CFR 50.92 Evaluation for the Proposed Changes to the Technical Specifications due to the Reactor Core Isolation Cooling Turbine Exhaust Pressure Trip Setpoint Modification for Edwin I. Hatch Nuclear Plant-Unit 1^(a)

Georgia Power Company (GPC) reviewed the requirements of 10 CFR 50.92 as they relate to the proposed change to the Technical Specifications due to the reactor core isolation cooling (RCIC) turbine exhaust pressure trip setpoint modification. The proposed Technical Specifications raise the trip setpoint/allowable value for the RCIC turbine exhaust pressure from 25 psig to 45 psig. As discussed in NEDC-30136, this change will increase RCIC availability during small and intermediate break loss-of-coolant accidents by allowing a longer period of RCIC operation before its turbine is tripped off by high pressure in the primary containment. Raising the setpoint also allows RCIC to provide a backup to high-pressure coolant injection (HPCI) over a range of small breaks and provides more time for an operator to recover other systems if either HPCI and/or automatic depressurization system are unavailable.

GPC reviewed the proposed change and considers it not to involve a significant hazards consideration for the following reasons:

1. It will not significantly increase the probability or consequences of an accident previously evaluated, because the radiological effects due to the increased RCIC availability during accident conditions are well within 10 CFR 20 limits.
2. It will not create the possibility of a new or different kind of accident from any accident previously evaluated, because RCIC will still operate as required by design.
3. It will not involve a significant reduction in a margin of safety, because the slight increase in onsite radiological effects is outweighed by the potential for increased RCIC operability.

a. See subsection 4B.1 (page 4-2) for discussion of proposed revisions.

10 CFR 50.92 Evaluation for the Proposed Changes to the Technical Specifications due to the Deletion of Drywell Pressure Sensors E11-N011A, B, C, D for Edwin I. Hatch Nuclear Plant-Unit 1^(a)

Georgia Power Company (GPC) reviewed the requirements of 10 CFR 50.92 as they relate to the proposed change to the Technical Specifications due to the deletion of drywell pressure sensors E11-N011A, B, C, D. This change proposes to make drywell pressure sensor configuration consistent with water levels 2 and 3 sensor logic. Drywell pressure sensors E11-N010A, B, C, D may be used to provide signals for all four systems of the emergency core cooling system and still maintain single failure criteria. The Technical Specifications change involves adding to the Remarks column all the functions of the drywell pressure sensors.

GPC has reviewed the proposed change and considers it not to involve a significant hazards consideration for the following reasons:

1. It will not significantly increase the probability or consequences of an accident previously evaluated, because the new logic configuration still fulfills the FSAR criteria.
2. It will not create the possibility of a new or different kind of accident from any previously evaluated, because the new logic will still basically operate in the same manner as the current configuration.
3. It will not involve a significant reduction in a margin of safety, because the current level of instrument redundancy will be maintained by the new logic.

a. See subsection 4B.2 (page 4-3) for discussion of proposed revisions.

10 CFR 50.92 Evaluation for the Proposed Change to the Post-Accident Monitoring Instrument Technical Specifications for Edwin I. Hatch Nuclear Plant-Unit 1^(a)

Georgia Power Company (GPC) reviewed the requirements of 10 CFR 50.92 as they relate to the proposed changes to the Technical Specifications due to the post-accident monitoring instrument modifications. The proposed Technical Specifications revised the instrument ranges for the reactor vessel water level, shroud level and reactor pressure recorders and indicators, which are being replaced to be compatible with ATTS. It is also proposed to revise the calibration frequency from a six month interval to once per operating cycle for the instrument loop but also require that the recorders themselves be calibrated once per twelve months. The yearly calibration for the recorders is the manufacturer's recommended interval. The manufacturer's recommended calibration frequency for the indicators is once per 5 years. Since the proposed loop surveillance is once per 18 months, an individual calibration frequency for the indicators is not required. These changes in calibration frequency take into account the abilities of ATTS and the new recorders.

GPC reviewed the proposed changes and considers them not to involve a significant hazards consideration for the following reasons:

1. They will not significantly increase the probability or consequences of an accident previously evaluated because the revisions to the instrument ranges merely updates information and the proposed calibration frequency is tailored to the new instruments.
2. They will not create the possibility of a new or different kind of accident from any accident previously evaluated, because the instrument functions, as described in the FSAR, are unchanged.
3. They will not involve a significant reduction in a margin of safety, because the revisions to the instrument ranges merely updates information and the proposed calibration frequency takes credit for the improved instrumentation.

a. See subsection 4B.3 (page 4-4) for discussion of proposed revisions.

10 CFR 50.92 Evaluation for the Proposed Trip Setpoint/Allowable Values for Rosemount Transmitters Changes to the Technical Specifications for Edwin I. Hatch Nuclear Plant-Unit 1^a

Georgia Power Company (GPC) reviewed the requirements of 10 CFR 50.92 as they relate to the proposed Technical Specification changes to the trip setpoint/allowable values for reactor vessel water levels 1, 2 and 3; shroud water level and reactor steam dome pressure instruments. The new values were determined using the criteria of Regulatory Guide 1.105 and the specifications of both the Barton Model 764 and Rosemount Model 1154 Transmitters. This will allow Rosemount transmitters, as well as, Bartons to be installed in the plant.

GPC reviewed the proposed changes and considers them not to involve a significant hazards consideration for the following reasons:

1. They will not significantly increase the probability or consequences of an accident previously evaluated, because the Barton and Rosemount transmitters are considered equivalent instruments. In addition, the new setpoints were calculated using the criteria of Regulatory Guide 1.105, and therefore, still meet the FSAR criteria.
2. They will not create the possibility of a new or different kind of accident from any accident previously evaluated, because the trip functions, as described in the FSAR, remain unchanged.
3. They will not involve a significant reduction in a margin of safety, because the original basis for the setpoints is maintained. In addition, the setpoints were determined using the criteria of Regulatory Guide 1.105.

a. See subsection 4B-4 (page 4-5) for discussion of proposed revisions.

10 CFR 50.92 Evaluation for the Proposed Reactor Steam Dome Pressure
Permissive Modification to the Technical Specifications for Edwin I. Hatch
Nuclear Plant-Unit 1^(a)

Georgia Power Company (GPC) reviewed the requirements of 10 CFR 50.92 as they relate to the proposed reactor steam dome pressure permissive modification to the Technical Specifications. This change proposes to delete the upper bound limit to the reactor steam dome pressure permissive to the CS and LPCI injection valves. The current Technical Specifications have an upper and lower limit. The 500 psig upper bound limit was originally in the Technical Specifications to provide overpressurization protection for the RHR system. However, the reactor pressure permissive signal requires a concurrent LOCA signal to open the normally closed injection valves to provide a flow path for LPCI injection. The concurrent signal requirements are intended to minimize the potential for inadvertent valve opening during normal power operation. During normal power operation, the injection valves also serve as the redundant isolation valves to the F050A,B valves. During accident conditions the LPCI signal takes precedence and demands the injection valves to open. The transient time at the pressure slightly above the minimum design pressure of the low pressure piping is relatively short. The containment isolation check valves (F050A,B) and the relief valves are capable of providing adequate overpressure protection during this short period in an accident.

GPC reviewed the proposed change and considers it not be involve a significant hazard consideration for the following reasons:

1. It will not significantly increase the probability or consequences of an accident previously evaluated because adequate overpressurization protection is still available for the system, and the system design as described in the FSAR is unchanged.
2. It will not create the possibility of a new or different kind of accident from any accident previously evaluated because the overpressurization protection of the system is maintained, and the system design as described in the FSAR is unchanged.
3. It will not involve a significant reduction in the margin of safety because the original basis of this Technical Specification, which is to ensure CS and LPCI operation as reactor pressure drops during accident conditions, is maintained. In addition, the new trip setpoint/allowable value was calculated using methodology previously approved by the NRC and is more conservative than the current value with respect to the lower analytical limit.

a. See subsection 4B-5 (page 4-6) for discussion of proposed revisions.

10 CFR 50.92 Evaluation for the Proposed Trip Function Identification
Changes to the Technical Specifications for Edwin I. Hatch Nuclear
Plant-Unit 1(a)

Georgia Power Company (GPC) reviewed the requirements of 10 CFR 50.92 as they relate to the proposed trip function identification changes to the Technical Specifications. Since the proposed changes only involve revisions in nomenclature, GPC considers them to be purely administrative in nature.

As discussed above, the proposed changes only involve changes in nomenclature. GPC determined that these proposed changes are consistent with Item (i) of the "Examples of Amendments that are Considered Not Likely to Involve Significant Hazards Considerations" listed on page 14,870 of the April 6, 1983, issue of the Federal Register and will not involve a significant hazards consideration.

a. See subsection 4B.6 (page 4-7) for discussion of proposed revisions.

10 CFR 50.92 Evaluation for the Proposed Miscellaneous Trip Setpoint/Allowable Value Modifications to the Technical Specifications for Edwin I. Hatch Nuclear Plant-Unit 1^a

Georgia Power Company (GPC) reviewed the requirements of 10 CFR 50.92 as they relate to the proposed miscellaneous trip setpoint/allowable value modifications to the Technical Specifications. The purpose of this change is to update the Technical Specifications trip setpoints being replaced by the analog transmitter trip system (ATTS). Since the time that original setpoints were determined, a better calculational method has been developed. This proposed change uses the Regulatory Guide 1.105 methodology in updating the setpoints for the instruments being replaced with the ATTS units, and takes credit for the improved error and drift characteristics of the new system. This change replaces the trip setpoints listed in the Technical Specifications which are the original analytical limits with the newly evaluated allowable values determined through Regulatory Guide 1.105 methodology.

GPC reviewed the proposed changes and considers them not to involve a significant hazards consideration for the following reasons:

1. They will not significantly increase the probability or consequences of an accident previously evaluated, because the new ATTS instruments are of a superior design as compared to the current instruments. In addition, the setpoints were determined using the criteria of Regulatory Guide 1.105, and therefore, still meet the Final Safety Analysis Report (FSAR) criteria.
2. They will not create the possibility of a new or different kind of accident from any accident previously evaluated, because the basic trip functions, as described in the FSAR, are unchanged.
3. They will not involve a significant reduction in a margin of safety, because for most trips, the original design basis was maintained. Any new design bases were fully addressed with regard to FSAR requirements. In addition, Regulatory Guide 1.105 criteria were used in the calculation of the new setpoints.

a. See subsection 4B.7 (page 4-8) for discussion of proposed revisions.

APPENDIX 2

NEDC-30126