COOPER NUCLEAR STATION
TABLE 3.2.B (PAGE 3)
RESIDUAL HEAT REMOVAL SYSTEM (LPCI MODE) CIRCUITRY REQUIREMENTS

Instrument	Instrument I.D. No.	Setting Limit	Minimum Number of Operable Components Per Trip System (1)	Action Required When Component Operability Is Not Assured
RHR Pump Low Flow	RHR-dPIS-125 A & B	$\geq$2500 gpm	1	A
Time Delays	RHR-TDR-K45, 1A&1B	$4.25 \leq T \leq 5.75$ min.	1	A
RHR Pump Start Time Delay	RHR-TDR-K75A & K70B	$4.5 \leq T \leq 5.5$ Sec.	1	A
	RHR-TDR-K75B & K70A	$\leq$.5 sec.	1	A
RHR Heat Exchanger Bypass T.D.	RHR-TDR-K93, A & B	$1.8 \leq T \leq 2.2$ min.	1	B
RHR Crosstie Valve Position	RHR-LMS-2	Valve Not closed	(3)	E
Bus 1A Low Volt. Aux. Relay	27 X 3/1A	Loss of Voltage	1	B
Bus 1B Low Volt. Aux. Relay	27 X 3/1B	Loss of Voltage	1	B
Bus 1F Low Volt. Aux. Relays	27 X 1/1F	Loss of Voltage	1	B
	27 X 2/1F	Loss of Voltage	1	B
Bus 1G Low Volt. Aux. Relays	27 X 1/1G	Loss of Voltage	1	B
	27 X 2/1G	Loss of Voltage		
Pump Discharge Line	CM-PS-266	$\geq$5 psig	(3)	D
	CM-PS-270	$\geq$15 psig	(3)	D
Emergency Buses Undervoltage Relays (degraded voltage)	27/1F-2, 27/1FA-2	3600 $\pm$5%	2	B
	27/1G-2, 27/1GB-2	8 second $\pm$2 sec.	2	B
		time delay	1	B
Emergency Buses Loss of Voltage Relays	27/1F-1, 27/1FA-1, 27/1G-1, 27/1GB-1, 27/ET-1, 27/ET-2	2900V $\pm$5% 5 second $\pm$1 sec. delay	1	B
Emergency Buses Under-Voltage Relays Timers	27X7/1F, 27X7/1G,	10 second $\pm$2 sec.	1	B

COOPER NUCLEAR STATION
TABLE 3.2.B (PAGE 5)
HPCI SYSTEM CIRCUITRY REQUIREMENTS

Instrument	Instrument I.D. No.	Setting Limit	Minimum Number of Operable Components Per Trip System (1)	Action Required When Component Operability Is Not Assured
Suppression Chamber High Water Level	HPCI-LS-91 A & B	2½" H_2O (5" Above Normal)	1(2)	A
HPCI Gland Seal Cond. Hotwell Level	HPCI-LS-356 B HPCI-LS-356 A	$\geq$18" $\leq$46"	1(3) 1(3)	A A
HPCI Turbine Stop Valve Monitor	HPCI-LMS-4	N.A.	1(2)	B
Suppression Chamber HPCI Suction Valve 23-58	HPCI-LMS-2	N.A.	1(2)	A
HPCI Control Oil Pressure Low	HPCI-PS-2787-H HPCI-PS-2787-L	$\geq$85 psig $\geq$20 psig	1(2)	B
Turbine Conditional Supervisory Alarm Actuation Timer	HPCI-TDR-K14	13.5$\leq$T$\leq$16.5 sec.	1(3)	E
Pump Discharge Line Low Pressure	CM-PS-268	$\geq$10 psig	(3)	D
HPCI Steamline High ΔP Actuation Timer	HPCI-TDR-K33 HPCI-TDR-K43	2.9$\leq$T$\leq$3.3 sec.	1	A

COOPER NUCLEAR STATION
TABLE 3.2.B (PAGE 6)
REACTOR CORE ISOLATION COOLING SYSTEM (RCIC) CIRCUITRY REQUIREMENTS

Instrument	Instrument I.D. No.	Setting Limit	Minimum Number of Operable Components Per Trip System (1)	Action Required When Component Operability Is Not Assured
RCIC High Turbine Exhaust Press.	RCIC-PS-72, A & B	$\leq$25 psig	1(2)	A
RCIC Low Pump Suction Press.	RCIC-PS-67-1	$\leq$-15" Hg	1(2)	
RCIC Steam Line Space Excess Temp.	RCIC-TS-79, A,B,C,&D RCIC-TS-80, A,B,C,&D RCIC-TS-81, A,B,C,&D RCIC-TS-82, A,B,C,&D	$\leq 200^{o}F$	2(4)	A
RCIC Steam Line High ΔP	RCIC-dPIS-83 & 84	370" $\leq S \leq$ 620" H_2O	1	A
RCIC Steam Supply Press. Low	RCIC-PS-87, A,B,C,&D	$\geq$50 psig	2(2)	A
RCIC Low Pump Disch. Flow	RCIC-FIS-57	$\geq$40 gpm	1(2)	A
Pump Discharge Line Low Pressure	CM-PS-269	$\geq$10 psig	(3)	D
RCIC Turbine Conditional Supervisory Alarm Timer	RCIC-TDR-K9	13.5 $\leq$ T $\leq$ 16.5	(3)	E
Reactor Low Water Level	10A-K80, A & B 10A-K79, A & B (NBI-LIS-72, A,B,C, & D)	$\geq$-37" Indicated Level	2(2)	A
Reactor High Water Level	NBI-LIS-101, A & C #2	$\leq$+58.5 Indicated Level	2(2)	A
RCIC Steamline High ΔP Actuation Timer	RCIC-TDR-K12 RCIC-TDR-K22	2.7$\leq$T$\leq$3.3 sec	1	A

COOPER NUCLEAR STATION
TABLE 4.2.B (Page 2)
RHR SYSTEM TEST & CALIBRATION FREQUENCIES

	Item	Item I.D. No.	Functional Test Freq.	Calibration Freq.	Instrument Check
Instrumentation					
1.	Drywell High Pressure	PC-PS-101, A, B, C & D	Once/Month (1)	Once/3 Months	None
2.	Reactor Vessel Shroud Level	NBI-LITS-73, A & B #1	Once/Month (1)	Once/3 Months	Once/Day
3.	Reactor Low Pressure	RR-PS-128 A & B	Once/Month (1)	Once/3 Months	None
4.	Reactor Low Pressure	NBI-PS-52 A & C NBI-PIS-52 B & D	Once/Month (1)	Once/3 Months	None
5.	Drywell Press.-Containment Spray	PC-PS-119, A,B,C & D	Once/Month (1)	Once/3 Months	None
6.	RHR Pump Discharge Press.	RHR-PS-120, A,B,C & D	Once/Month (1)	Once/3 Months	None
7.	RHR Pump Discharge Press.	RHR-PS-105, A,B,C & D	Once/Month (1)	Once/3 Months	None
8.	RHR Pump Low Flow Switch	RHR-dPIS-125 A & B	Once/Month (1)	Once 3 Months	None
9.	RHR Pump Start Time Delay	RHR-TDR-K70, A & B	Once/Month (1)	Once/Oper. Cycle	None
10.	RHR Pump Start Time Delay	RHR-TDR-K75, A & B	Once/Month (1)	Once/Oper. Cycle	None
11.	RHR Heat Exchanger Bypass T.D.	RHR-TDR-K93, A & B	Once/Month (1)	Once/Oper. Cycle	None
12.	RHR Cross Tie Valve Position	RHR-LMS-2	Once/Month (1)	N.A.	
13.	Low Voltage Relays	27 X 3/1A	(7)		None
14.	Low Voltage Relays	27 X 3/1B	(7)		None
15.	Low Voltage Relays	27 x 2/1F, 27 X 2/1G	(7)		None
16.	Low Voltage Relays	27 X 1/1F, 27 X 1/1G	(7)		None
17.	Pump Disch. Line Press. Low	CM-PS-266, CM-PS-270	Once/3 Months	Once/3 Months	None
18.	Emergency buses Undervoltage Relays (Degraded Voltage)	27/1F-2, 27/1FA-2, 27/1G-2, 27/1GB-2	Once/Month	Once/18 Months	Once/12 hrs.
19.	Emergency Buses Loss of Voltage Relays	27/1F-1, 27/1FA-1, 27/1G-1, 27/1GB-1, 27/ET-1, 27/ET-2	Once/Month	Once/18 Months	Once/12 hrs.
20.	Emergency Buses Undervoltage Relays Timers	27X7/1F, 27X7/1G	Once/Month	Once/18 Months	None

TABLE 4.2.C

SURVEILLANCE REQUIREMENTS FOR ROD WITHDRAWAL BLOCK INSTRUMENTATION

Function	Functional Test Freq.	Calibration Freq.	Instrument Check
APRM Upscale (Flow Bias)	(1) (3)	Once/3 Months	Once/Day
APRM Upscale (Startup Mode)	(1) (3)	Once/3 Months	Once/Day
APRM Downscale	(1) (3)	Once/3 Months	Once/Day
APRM Inoperative	(1) (3)	N.A.	Once/Day
RBM Upscale (Flow Bias)	(1) (3)	Once/6 Months	Once/Day
RBM Downscale	(1) (3)	Once/6 Months	Once/Day
RBM Inoperative	(1) (3)	N.A.	Once/Day
IRM Upscale	(1) (2) (3)	Once/3 Months	Once/Day
IRM Downscale	(1) (2) (3)	Once/3 Months	Once/Day
IRM Detector Not Full In	(2) (Once/operating cycle)	Once/Oper. Cycle (10)	Once/Day
IRM Inoperative	(1) (2) (3)	N.A.	N.A.
SRM Upscale	(1) (2) (3)	Once/3 Months	Once/Day
SRM Downscale	(1) (2) (3)	Once/3 Months	Once/Day
SRM Detector Not Full In	(2) (Once/operating cycle)	Once/Oper. Cycle (10)	N.A.
SRM Inoperative	(1) (2) (3)	N.A.	N.A.
Flow Bias Comparator	(1) (8)	Once/Oper. Cycle	N.A.
Flow Bias Upscale	(1) (8)	Once/3 Months	N.A.
Rod Block Logic	(9)	N.A.	N.A.
RSCS Rod Group C Bypass	(1)	Once/3 Months	N.A.

COOPER NUCLEAR STATION
TABLE 4.2.F
PRIMARY CONTAINMENT SURVEILLANCE INSTRUMENTATION
TEST AND CALIBRATION FREQUENCIES

Instrument	Instrument I.D. No.	Calibration Frequency	Instrument Check
Reactor Water Level	NBI-LI-85A	Once/6 Months	Each Shift
	NBI-LI-85B	Once/6 Months	Each Shift
Reactor Pressure	RFC-PI-90A	Once/6 Months	Each Shift
	RFC-PI-90B	Once/6 Months	Each Shift
Drywell Pressure	PC-PR-512A	Once/6 Months	Each Shift
	PC-PI-512B	Once/6 Months	Each Shift
Drywell Temperature	PC-TR-503	Once/6 Months	Each Shift
	PC-TI-505	Once/6 Months	Each Shift
Suppression Chamber Air Temperature	PC-TR-21A	Once/6 Months	Each Shift
	PC-TR-23, Ch. 1 & 2	Once/6 Months	Each Shift
Suppression Chamber Water Temperature	PC-TR-21B	Once/6 Months	Each Shift
	PC-TR-22, Ch. 1 & 2	Once/6 Months	Each Shift
Suppression Chamber Water Level	PC-LI-10	Once/6 Months	Each Shift
	PC-LR-11	Once/6 Months	Each Shift
	PC-LI-12	Once/6 Months	Each Shift
	PC-LI-13	Once/6 Months	Each Shift
Suppression Chamber Pressure	PC-PR-20	Once/6 Months	Each Shift
Control Rod Position	N.A.	N.A.	Each Shift
Neutron Monitoring (APRM)	N.A.	Once/Week	Each Shift
Torus to Drywell Differential Pressure	PC-dPR-20	Once/6 Months	Each Shift
Suppression Chamber/ Drywell Pressure (AP)	PC-PR-20/513 (2)	Once/6 Months	Each Shift

NOTES FOR TABLES 4.2.A THROUGH 4.2.F

1. Initially once every month until exposure (M as defined on Figure 4.1.1) is 2.0×10^{5}; thereafter, according to Figure 4.1.1(after NRC approval). The compilation of instrument failure rate data may include data obtained from other boiling water reactors for which the same design instrument operates in an environment similar to that of CNS.

2. Functional tests shall be performed before each startup with a required frequency not to exceed once per week.

3. This instrumentation is excepted from the functional test definition. The functional test will consist of applying simulated inputs. Local alarm lights representing upscale and downscale trips will be verified but no rod block will be produced at this time. The inoperative trip will be initiated to produce a rod block (SRM and IRM inoperative also bypassed with the mode switch in RUN). The functions that cannot be verified to produce a rod block directly will be verified during the operating cycle.

4. Simulated automatic actuation shall be performed once each operating cycle. Where possible, all logic system functional tests will be performed using the test jacks.

5. Reactor low water level, high drywell pressure and high radiation main steam line tunnel are not included on Table 4.2.A since they are tested on Table 4.1.2.

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

7. These units are tested as part of the Core Spray System tests.

8. The flow bias comparator will be tested by putting one flow unit in "Test" (producing 1/2 scram) and adjusting the test input to obtain comparator rod block. The flow bias upscale will be verified by observing a local upscale trip light during operation and verifying that it will produce a rod block during the operating cycle.

9. Performed during operating cycle. Portions of the logic is checked more frequently during functional tests of the functions that produce a rod block.

10. The detector will be inserted during each operating cycle and the proper amount of travel into the core verified.

3.2 BASES

In addition to reactor protection instrumentation which initiates a reactor scram, protective instrumentation has been provided which initiates action to mitigate the consequences of accidents which are beyond the operator's ability to control, or terminates operator errors before they result in serious consequences. This set of specifications provides the limiting conditions of operation for the primary system isolation function, initiation of the core cooling systems, control rod block and standby gas treatment systems. The objectives of the Specifications are (i) to assure the effectiveness of the protective instrumentation when required 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.

Some of the settings on the instrumentation that initiate or control core and containment cooling have tolerances explicitly stated where the high and low values are both critical and may have a substantial effect on safety. The set points of other instrumentation, where only the high or low end of the setting has a direct bearing on safety, are chosen at a level away from the normal operating range to prevent inadvertent actuation of the safety system involved and exposure to abnormal situations.

Actuation of primary containment valves is initiated by protective instrumentation shown in Table 3.2.A which senses the conditions for which isolation is required. Such instrumentation must be available whenever primary containment integrity is required.

The instrumentation which initiates primary system isolation is connected in a dual bus arrangement.

The low water level instrumentation,n, set to trip at 176.5" (+12.5") above the top of the active fuel, closes all isolation valves except those in Groups 1, 4, and 5. Details of valve grouping and required closing times are given in Specification 3.7. For valves which isolate at this level this trip setting is adequate to prevent core uncovery in the case of a break in the largest line assuming a 60 second valve closing time. Required closing times are less than this.

The low reactor water level instrumentation is set to trip when reactor water level is 127" (-37") above the top of the active fuel. This trip closes Main Steam Line Isolation Valves, Main Steam Drain Valves, Recirc Sample Valves (Groups 1 and 7), initiates the HPCI and RCIC. The low reactor water level instrumentation is set to trip when the water level is 19" (-145") above the top of the active fuel. This trip activates the remainder of the CSCS subsystems, and starts the emergency diesel generators. These trip level settings were chosen to be high enough to prevent spurious actuation but low enough to initiate CSCS operation and primary system isolation so that post accident cooling can be accomplished.

and the guidelines of 10CFR100 will not be exceeded. For large breaks up to the complete circumferential break of a 28-inch recirculation line and with the trip setting given above, CSCS initiation and primary system isolation are initiated in time to meet the above criteria. Reference Paragraph VI.5.3.1 FSAR.

The high drywell pressure instrumentation is a diverse signal for malfunctions to the water level instrumentation and in addition to initiating CSCS, it causes isolation of Group 2 and 6 isolation valves. For the breaks discussed above, this instrumentation will generally initiate CSCS operation before the low-low-low water level instrumentation; thus the results given above are applicable here also. The water level instrumentation initiates protection for the full spectrum of loss-of-coolant accidents and causes isolation of all isolation valves except Groups 4 and 5.

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. The primary function of the instrumentation is to detect a break in the main steam line. For the worst case of accident, main steam line break outside the drywell, a trip setting of 140% of rated steam flow in conjunction with the flow limiters and main steam line valve closure, limits the mass inventory loss such that fuel is not uncovered, fuel temperatures peak at approximately 1000°F and release of radioactivity to the environs is below 10CFR100 guidelines. Reference Section SIV.6.5 FSAR.

Temperature monitoring instrumentation is provided in the main steam tunnel and along the steam line in the turbine building to detect leaks in these areas. Trips are provided on this instrumentation and when exceeded, cause closure of isolation valves. See Spec. 3.7 for Valve Group. The setting is 200°F for the main steam leak detection system. For large breaks, the high steam flow instrumentation is a backup to the temp. instrumentation.

High radiation monitors in the main steam tunnel have been provided to detect gross fuel failure as in the control rod drop accident. With the established setting of 3 times normal background, and main steam line isolation valve closure, fission product release is limited so that 10CFR100 guidelines are not exceeded for this accident. Reference Section XIV.6.2 FSAR.

Pressure instrumentation is provided to close the main steam isolation valves in RUN Mode when the main steam line pressure drops below Specification 2.1.A.6. The Reactor Pressure Vessel thermal transient due to an inadvertent opening of the turbine bypass valves when not in the RUN Mode is less severe than the loss of feedwater analyzed in Section XIV.5 of the FSAR, therefore, closure of the Main Steam Isolation valves for thermal transient protection when not in RUN mode is not required.

The HPCI high flow and temperature instrumentation are provided to detect a

3.3 and 4.3 BASES (cont'd.)

The degraded performance of the original drive (CRD7RDB144A) under dirty operating conditions and the insensitivity of the redesigned drive (CRD7RDB144B) has been demonstrated by a series of engineering tests under simulated reactor operating conditions. The successful performance of the new drive under actual operating conditions has also been demonstrated by consistently good in-service test results for plants using the new drive and may be inferred from plants using the older model drive with a modified (larger screen size) internal filter which is less prone to plugging. Data has been documented by surveillance reports in various operating plants. These include Oyster Creek, Monticello, Dresden 2 and Dresden 3. Approximately 5000 drive tests have been recorded to date.

Following identification of the "plugged filter" problem, very frequent scram tests were necessary to ensure proper performance. However, the more frequent scram tests are now considered totally unnecessary and unwise for the following reasons:

1. Erratic scram performance has been identified as due to an obstructed drive filter in type "A" drives. The drives in CNS are of the new "B" type design whose scram performance is unaffected by filter condition.

2. The dirt load is primarily released during startup of the reactor when the reactor and its systems are first subjected to flows and pressure and thermal stresses. Special attention and measures are now being taken to assure cleaner systems. Reactors with drives identical or similar (shorter stroke, smaller piston areas) have operated through many refueling cycles with no sudden or erratic changes in scram performance. This preoperational and startup testing is sufficient to detect anomalous drive performance.

3. The 72-hour outage limit which initiated the start of the frequent scram testing is arbitrary, having no logical basis other than quantifying a "major outage" which might reasonably be caused by an event so severe as to possibly affect drive performance. This requirement is unwise because it provides an incentive for shortcut actions to hasten returning "on line" to avoid the additional testing due to 72-hour outage.

   The surveillance requirement for scram testing of all the control rods after each refueling outage and 10% of the control rods at 16-week intervals is adequate for determining the operability of the control rod system yet is not so frequent as to cause excessive wear on the control rod system components.

   The numerical values assigned to the predicted scram performance are based on the analysis of data from other BWR's with control rod drives the same as those on Cooper Nuclear Station.

LIMITING CONDITIONS FOR OPERATION	SURVEILLANCE REQUIREMENTS
3.6.D Safety and Relief Valves	4.6.D Safety and Relief Valves
1. During reactor power operating conditions and prior to reactor startup from a Cold Condition, or whenever reactor coolant pressure is greater than atmospheric and temperature greater than 212°F, all three safety valves and the safety modes of all relief valves shall be operable, except as specified in 3.6.D.2.	1. Approximately half of the safety valves and relief valves shall be checked or replaced with bench checked valves once per operating cycle. All valves will be tested every two cycles. The set point of the safety valves shall be as specified in Specification 2.2.
2.	2. At least one of the relief valves shall be disassembled and inspected each refueling outage.
a. From and after the date that the safety valve function of one relief valve is made or found to be inoperable, continued reactor operation is permissible only during the succeeding thirty days unless such valve function is sooner made operable.	
b. From and after the date that the safety valve function of two relief valves is made or found to be inoperable, continued reactor operation is permissible only during the succeeding seven days unless such valve function is sooner made operable.	
3. If Specification 3.6.D.1 is not met, an orderly shutdown shall be initiated and the reactor coolant pressure shall be reduced to a cold shutdown condition within 24 hours.	3. The integrity of the relief safety valve bellows on any three stage valve shall be continuously monitored.
4. From and after the date that position indication on any one relief valve is made or found to be inoperable, continued reactor operation is permissible only during the succeeding thirty days unless such valve position indication is sooner made operable.	4. The operability of the bellows monitoring system shall be demonstrated once every three months when three stage valves are installed. 5. Once per operating cycle, with the reactor pressure $\geq$ 100 psig, each relief valve shall be manually opened until the main turbine bypass valves have closed to compensate for relief valve opening. 6. a. Operability of the relief valve position indicating pressure switches and the safety valve position indicating thermocouples shall be demonstrated once per operating cycle. b. An Instrument Check of the safety and relief valve position indicating devices shall be performed monthly.

COOPER NUCLEAR STATION
TABLE 3.7.1 (Page 2)
PRIMARY CONTAINMENT ISOLATION VALVES

Valve & Steam	Number of Power Operated Valves		Maximum Operating Time (Sec) (1)	Normal Position (2)	Action On Initiating Signal (3)
	Inboard	Outboard			
Primary Containment Purge & Vent PC-246AV, PC-231MV		2	15	C	SC
Primary Containment & N_2 Supply PC-238AV, PC-232MV		2	15	C	SC
ACAD Supply					
MV 1303, MV 1304		2	15	O	GC
MV 1305, MV 1306		2	15	O	GC
Suppression Chamber Purge & Vent PC-230MV Bypass (PC-305MV)		1	40	C	SC(4)
Primary Containment Purge & Vent PC-231MV Bypass (PC-306MV)		1	40	C	SC(4)

NOTES FOR TABLE 3.7.1

1. Maximum valve operating times in seconds in the closed direction. This is the direction required for Primary Containment isolation.

2. Normal position indicates the normal valve position during power operations.

   O = Open
   C = Closed

3. Action on initiating signal indicates the valve operation after the signal initiation.

   GC = Goes Closed
   SC = Stays Closed

4. PC-305MV & PC-306MV have override switches (key operated) which can be used to open valves when isolation signals are in.

4.9 BASES

The monthly test of the diesel generator is conducted to check for equipment failures and deterioration. Testing is conducted up to equilibrium operating conditions to demonstrate proper operation at these conditions. The diesel generator will be manually started, synchronized and connected to the bus and load picked up. The diesel generator should be loaded to at least 35% of rated load to prevent fouling of the engine. It is expected that the diesel generator will be run for at least two hours. Diesel generator experience at other generating stations indicates that the testing frequency is adequate and provides a high reliability of operation should the system be required.

Each diesel generator has two air compressors and two air receivers for starting. It is expected that the air compressors will run only infrequently. During the monthly check of the diesel generator, each receiver in each set of receivers will be drawn down below the point at which the corresponding compressor automatically starts to check operation and the ability of the compressors to recharge the receivers.

The diesel generator fuel consumption rate at full load is approximately 275 gallons per hour. Thus, the monthly load test of the diesel generators will test the operation and the ability of the fuel oil transfer pumps to refill the day tank and will check the operation of these pumps from the emergency source.

The test of the diesel generator during the refueling outage will be more comprehensive in that it will functionally test the system; i.e, it will check diesel generator starting and closure of diesel generator breaker and sequencing of load on the diesel generator. The diesel generator will be started by simulation of a loss-of-coolant accident. In addition, an undervoltage condition will be imposed to simulate a loss of off-site power.

Periodic tests between refueling outages verify the ability of the diesel generator to run at full load and the core and containment cooling pumps to deliver full flow. Periodic testing of the various components, plus a functional test once-a-cycle, is sufficient to maintain adequate reliability.

Although station batteries will deteriorate with time, utility experience indicates there is almost no possibility of precipitous failure. The type of surveillance described in this specification is that which has been demonstrated over the years to provide an indication of a cell becoming irregular or unserviceable long before it becomes a failure. In addition, the checks described also provide adequate indication that the batteries have the specified ampere-hour capability.

The diesel fuel oil quality must be checked to ensure proper operation of the diesel generators. Water content should be minimized because water in the

6.2 (cont'd)

1. Membership

   a. Senior Division Manager of Power Operations (chairman)

   b. Division Manager of Licensing and Quality Assurance (alternate Chairman)

   c. Division Manager of Power Projects

   d. Division Manager of Power Supply

   e. Division Manager of Environmental Affairs

   f. Consultants (as required)

   The Board members shall collectvely have the capability required to review problems in the following areas: nuclear power plant operations, nuclear engineering, chemistry and radiochemistry, metallurgy, instrumentation and control, radiological safety, mechanical and electrical engineering, and other appropriate fields associated with the unique characteristics of the nuclear power plant involved. When the nature of a particular problem dictates, special consultants will be utilized.

   Alternate members shall be appointed in writing by the Board Chairman to serve on a temporary basis; however, no more than two alternates shall serve on the Board at any one time.

2. Meeting frequency: Semiannually, and as required on call of the Chairman.

3. Quorum: Chairman or Vice Chairman, plus three members including alternates. No more than a minority of the quorum shall be from groups holding line responsibility for the operation of the plant.

4. Responsibilities: The following subjects shall be reported to and reviewed by the NPPD Safety Review and Audit Board.

   a. The safety evaluations for 1) changes to procedures, equipment or systems and 2) tests or experiments completed under the provision of Section 50.59, 10 CFR, to verify that such actions did not constitute an unreviewed safety question.

   b. Proposed changes to procedures, equipment or systems which involve an unreviewed safety question as defined in Section 50.59, 10 CFR.

1. A tabulation on an annual basis of the number of station, utility and other personnel (including contractors) receiving exposures greater than 100 mrem/yr and their associated man rem exposure according to work and job functions, 1/ e.g., reactor operations and surveillance, inservice inspection, routine maintenance, special maintenance (describe maintenance), waste processing, and refueling. The dose assignment to various duty functions may be estimates based on pocket dosimeter, TLD, or film badge measurements. Small exposures totaling less than 20% of the individual total dose need not be accounted for. In the aggregate, at least 80% of the total whole body dose received from external sources shall be assigned to specific major work functions.

2. A summary description of facility changes, tests or experiments in accordance with the requirements of 10CFR50.59(b).

3. Pursuant to 3.8.A, a report of radioactive source leak testing. This report is required only if the tests reveal the presence of 0.005 microcuries or more of removable contamination.

D. Monthly Operating Report

Routine reports of operating statistics, shutdown experience, and a narrative summary of operating experience relating to safe operation of the facility, shall be submitted on a monthly basis to the Director, Office of Management Information and Program Control, U.S. Nuclear Regulatory Commission, Washington, DC 20555, with a copy to the appropriate Regional Office, no later than the tenth of each month following the calendar month covered by the report.

6.7.2. Reportable Occurrences

Reportable occurrences, including corrective actions and measures to prevent reoccurrence, shall be reported to the NRC. Supplemental reports may be required to fully describe final resolution of occurence. In case of corrected or supplemental reports, a licensee event report shall be completed and reference shall be made to the original report date.

1/ This tabulation supplements the requirements of §20.407 of 10CFR Part 20.

6.7.3. Unique Reporting Requirements

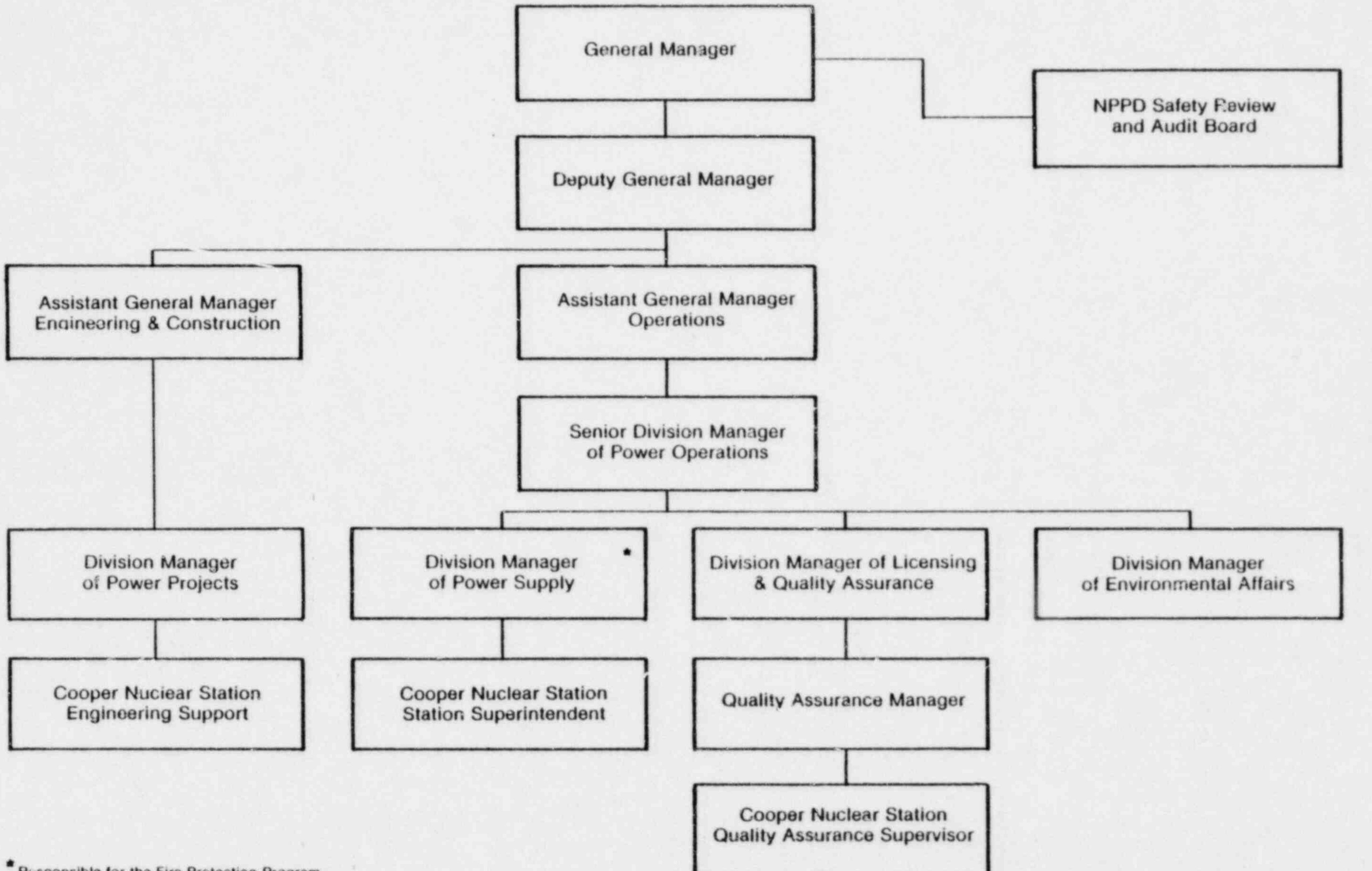
Reports shall be submitted to the Director, Nuclear Reactor Regulation, USNRC, Washington, DC 20555, as follows:

A. Reports on the following areas shall be submitted as noted:

None.

Nebraska Public Power District

MANAGEMENT ORGANIZATION CHART



* Responsible for the Fire Protection Program

Figure 6.1.1
NPPD Management
Organization Chart