ATTACHMENT

EDWIN I. HATCH NUCLEAR PLANT
UNIT 1 AND UNIT 2

IMPROVED TECHNICAL SPECIFICATIONS

Revision C

EDWIN I. HATCH NUCLEAR PLANT
IMPROVED TECHNICAL SPECIFICATIONS

REVISION INSERTION INSTRUCTIONS
REVISION C

Page	Instruction
Cover sheet (Aplication of Selection Criteria)	Discard
U1 Matrix page 4 of 14	Replace
U2 Matrix page 6 of 14	Replace
Cover sheet (U1 Improved Specifications)	Discard
3.3-21	Replace
3.3-67	Replace
3.3-68A	Add
3.8-7	Replace
3.8-19	Replace
3.8-39	Replace
5.0-1	Replace
5.0-3	Replace
5.0-19	Replace
Cover sheet (Unit 1 Improved Bases)	Discard
B 3.3-67	Replace
B 3.3-201 through 3.3-205	Replace (with 6 sheets)
B 3.8-3	Replace
B 3.8-20A	Replace
B 3.8-37	Replace
B 3.8-39	Replace
B 3.8-77	Replace
B 3.8-79	Replace
B 3.8-87	Replace
B 3.8-89	Replace
Cover sheet (U1 CTS Markup & DOC)[a]	Discard
CTS 3.2-23B (1 of 4)	Replace
CTS 3.2-49A (2 of 4)	Replace
CTS 3.9-4 (3 of 4)	Replace
CTS 3.9-4A (4 of 4)	Replace
1 (DOC ITS 3.3.8.1)	Replace
2 (DOC ITS 3.3.8.1)	Replace
2A (DOC ITS 3.3.8.1)	Add
3 (DOC ITS 3.3.8.1)	Replace
4 (DOC ITS 3.3.8.1)	Replace
5 (DOC ITS 3.3.8.1)	Replace

a. In replacing each CTS page, reference the upper right corner for appropriate ITS section.

Revision C Insertion Instructions (continued)

Page	Instruction
(U1 CTS Markup & DOC) continued	
CTS 3.9-2 (2 of 13)	Replace
CTS 3.9-6b (10 of 13)	Replace
5 (DOC ITS 3.8.1)	Replace
6 (DOC ITS 3.8.1)	Replace
10 (DOC ITS 3.8.1)	Replace
CTS 3.9-3 (1 of 3)	Replace
1 (DOC ITS 3.8.7)	Replace
4 (DOC ITS 3.8.7)	Replace
INSERTS For ITS 5.1	Replace
CTS 6-18 (8 of 10)	Replace
4 (DOC ITS 5.6)	Replace
Cover sheet (U1 No Sig Hazards D'tion)	Discard
2 (NSHD ITS 3.3.8.1)	Discard
3 (NSHD ITS 3.3.8.1)	Discard
12 (NSHD ITS 3.8.1)	Discard
Cover sheet (U2 Improved Specifications)	Discard
3.3-23	Replace
3.3-69	Replace
3.3-70A	Add
3.8-7	Replace
3.8-19	Replace
3.8-39	Replace
3.8-40A	Replace
5.0-1	Replace
5.0-3	Replace
5.0-19	Replace
Cover sheet (U2 Improved Bases)	Discard
B 3.3-67	Replace
B 3.3-201 through 3.3-205	Replace (6 sheets)
B 3.8-3	Replace
B 3.8-21	Replace
B 3.8-37	Replace
B 3.8-39	Replace
B 3.8-77	Replace
B 3.8-79	Replace
B 3.8-87	Replace
B 3.8-89	Replace

Revision C Insertion Instructions (continued)

Page	Instruction
Cover sheet (U2 CTS Markup & DOC)[a]	Discard
CTS 3/4 3-63 (1 of 3)	Replace
CTS 3/4 3-64 (2 of 3)	Replace
CTS 3/4 3-65 (3 of 3)	Replace
1 (DOC ITS 3.3.8.1)	Replace
1A (DOC ITS 3.3.8.1)	Add
2 (DOC ITS 3.3.8.1)	Replace
3 (DOC ITS 3.3.8.1)	Replace
4 (DOC ITS 3.3.8.1)	Replace
5 (DOC ITS 3.3.8.1)	Replace
CTS 3/4 8-3 (3 of 11)	Replace
CTS 3/4 8-7 (9 of 11)	Replace
CTS 3/4 8-8 (10 of 11)	Replace
4 (DOC ITS 3.8.1)	Replace
5 (DOC ITS 3.8.1)	Replace
8 (DOC ITS 3.8.1)	Replace
CTS 3/4 8-10 (1 of 2)	Replace
CTS 3/4 8-13 (2 of 2)	Replace
2 (DOC ITS 3.8.7)	Replace
INSERT 1 for ITS 5.1	Replace
CTS 3/4 8-7 (8 of 9)	Replace
CTS 3/4 3-54A (9 of 9)	Replace
4 (DOC ITS 5.6)	Discard
Cover sheet (U2 No Sig Hazards D'tion)	Discard
2 (NSHD 3.3.8.1)	Discard
3 (NSHD 3.3.8.1)	Discard
11 (NSHD 3.8.1)	Replace
1 (NSHD 5.6)	Replace
Cover sheet (NUREG 1433 Comparison - Specs)	Discard
3.3-21	Replace
3.3-73	Replace
3.3-75	Replace
3.8-5	Replace
3.8-17	Replace
3.8-37	Replace
INSERT LOC 3.8.7 (U1 Version)	Replace
INSERT LOC 3.8.7 (U2 Version)	Replace
INSERT A/B 3.8.7	Replace
5.0-1	Replace
INSERT B for NUREG 5.2.2	Replace
5.0-37	Replace

a. In replacing each CTS page, reference the upper right corner for appropriate ITS section.

Revision C Insertion Instructions (continued)

Page	Instruction
Cover sheet (NUREG 1433 Comparison - Bases)	Discard
B 3.3-67	Replace
B 3.3-219	Replace
INSERT 1 3.3.8.1 Background Section	Add (following p. B 3.3-219)
INSERT 6 3.3.8.1 Background Section	Add (following INSERT 1 3.3.8.1)
INSERT 2 3.3.8.1 Applicable Safety Analysis Section	Add (following INSERT 6 3.3.8.1)
INSERT 3 3.3.8.1 Applicable Safety Analysis Section	Add (following INSERT 2 3.3.8.1)
B 3.3-221	Replace
INSERT 4 3.3.8.1 Applicable Safety Analysis Section	Add (following p. B 3.3-221)
INSERT 5 3.3.8.1 Applicable Safety Analysis Section	Add (following INSERT 4 3.3.8.1)
B 3.3-223	Replace
INSERT C ACTIONS	Add (following B 3.3-223)
INSERT A for proposed BASES B 3.3.8.1	Replace
B 3.3-225	Replace
B 3.8-3	Replace
B 3.8-17	Replace
B 3.8-31	Replace
B 3.8-33	Replace
B 3.8-34 INSERT Ref	Replace
B 3.8-77	Replace
B 3.8-79	Replace
INSERT LOC 3.8.7-2	Replace
B 3.8-87	Replace
INSERT Table 3.8.7-1 (Unit 1)	Discard
INSERT Table 3.8.7-1 (continued) (Unit 1 version)	Discard
INSERT Table 3.8.7-1 (Unit 2)	Discard
INSERT Table 3.8.7-1 (continued) (Unit 2 version)	Discard
Cover sheet (NUREG 1433 J for Deviation)	Discard
Section 3.3 p.8	Replace
Section 3.3 p.11	Replace
Section 3.3 p.12	Replace
Section 3.8 p. 7	Replace
Section 3.8 p. 7B	Replace
Section 5.0 p. 4	Replace
Section 5.0 p. 4A	Replace

APPLICATION OF SELECTION CRITERIA

SUMMARY DISPOSITION MATRIX
PLANT HATCH UNIT 1

Current Unit 1 Number	Title	STS Rev. 4 Number	New Unit 1 TS Number	Retained/ Criterion for Inclusion	Bases for Inclusion/Exclusion[a][c]
3/4.2.H.4	Control Room Intake Radiation Monitors	3/4.3.7.1.5	3.3.7.1	Yes-3	Actuates to maintain control room habitability so that operation can continue from the control room following a DBA.
3/4.2.H.5	Main Steam Line Radiation Monitor	None	Deleted	No	Deleted. See radiation monitoring technical change discussion for MSLRM.
3/4.2.I	Initiates Recirculation Pump Trip	3/4.3.4.1 3/4.3.4.2	3.3.4.1 3.3.4.2		
3/4.2.I.1/2	ATWS-RPT	3/4.3.4.1	3.3.4.2	Yes-4	ATWS-RPT is being retained in accordance with the NRC Final Policy Statement on Technical Specification Improvements due to risk significance.
3/4.2.I.3	EOC-RPT	3/4.3.4.2	3.3.4.1	Yes-3	EOC-RPT aids the reactor scram in protecting fuel cladding integrity by ensuring the fuel cladding integrity Safety Limit is not exceeded during a load rejection or turbine trip transient.
3/4.2.J	Monitors Leakage into the Drywell	3/4.4.3	3.4.5	Yes-1	Leak detection is used to indicate a significant abnormal condition of the reactor coolant pressure boundary.
3/4.2.K	Provides Surveillance Information	3/4.3.7.5	3.3.3.1	Yes-3	RG 1.97 Type A and Category 1 variables retained. See Appendix A, Page 11 for full discussion of all variables.
3/4.2.L	Degraded Station Voltage Protection Instrumentation	3/4.3.3.5			
3/4.2.L.1	4.16kv Emergency Bus Undervoltage Relay (Loss of Voltage Condition)	3/4.3.3.5.1	3.3.8.1	Yes-3	Actuates DGs to mitigate consequences of a loss of offsite power event.
3/4.2.L.2	4.16kv Emergency Bus Undervoltage Relay (Degraded Voltage Condition)	3/4.3.3.5.2	3.3.8.1	Yes-3	Actuates DGs to mitigate consequences of degraded voltage condition.
3/4.2.M	Deleted in Amendment No. 186				
3/4.2.N	Arms Low Low Set S/RV System	3/4.4.2.1 3/4.4.2.2	3.3.6.3	Yes-3	Actuates LLS S/RVs, which are assumed to function in the containment loading safety analysis.
None	Remote Shutdown System	3/4.3.7.4	3.3.3.2	Yes-4	Being added as directed by the NRC as it is a significant contributor to risk reduction.
None	Feedwater and Main Turbine Trip Instrumentation	3/4.3.9	3.3.2.2	Yes-3	Acts to limit feedwater addition to the reactor vessel on feedwater controller failure consistent with safety analysis assumptions. Limits neutron flux peak and thermal transient to avoid fuel damage.

Current Unit 2 TS Number	Title	New Unit 2 TS Number	Retained/Criterion for Inclusion	Bases for Inclusion/Exclusion[(a)(c)]
3/4.3.6.10	Explosive Gas Monitoring Instrumentation	Relocated	No	See Appendix A, Page 11.
3/4.3.7	Turbine Overspeed Protection System	Relocated	No	See Appendix A, Page 12.
3/4.3.8	Degraded Station Voltage Protection Instrumentation	3.3.8.1		
3/4.3.8.1	4.16kv Emergency Bus Undervoltage Relay (Loss of Voltage Condition)	3.3.8.1	Yes-3	Actuates DGs to mitigate consequences of a loss of offsite power event.
3/4.3.8.2	4.16kv Emergency Bus Undervoltage Relay (Degraded Voltage Condition)	3.3.8.1	Yes-3	Actuates DGs to mitigate consequences of degraded voltage condition.
3/4.3.9	Recirculation Pump Trip Actuation Instrumentation			
3/4.3.9.1	ATWS Recirculation Pump Trip System Instrumentation	3.3.4.2	Yes-4	ATWS-RPT is being retained in accordance with the NRC Final Policy Statement on Technical Specification Improvements due to risk significance.
3/4.3.9.2	End-of-Cycle Recirculation Pump Trip System Instrumentation	3.3.4.1	Yes-3	EOC-RPT aids the reactor scram in protecting fuel cladding integrity by ensuring the fuel cladding integrity safety limit is not exceeded during a load rejection or turbine trip transient.
None	Feedwater and Main Turbine Trip Instrumentation	3.3.2.2	Yes-3	Acts to limit feedwater addition to the reactor vessel on feedwater controller failure consistent with safety analysis assumptions. Limits neutron flux peak and thermal transient to avoid fuel damage.
3/4.4	REACTOR COOLANT SYSTEM	3.4		
3/4.4.1	Recirculation System			
3/4.4.1.1	Recirculation Loops	3.4.1	Yes-2	Recirculation loop flow is an initial condition in the safety analysis.
3/4.4.1.2	Jet Pumps	3.4.2	Yes-3	Jet pump operability is assumed in the LOCA analyses to assure adequate core reflood capability.
3/4.4.1.3	Idle Recirculation Loop Startup	3.4.9	Yes-2	Establishes initial conditions to operation such that operation is prohibited in areas or at temperature rate changes that might cause undetected flaws to propagate, in turn challenging the reactor coolant pressure boundary integrity.
3/4.4.2	Safety/Relief Valves			
3/4.4.2.1	Safety/Relief Valves	3.3.6.3 3.4.3	Yes-3	A minimum number of S/RVs is assumed in the safety analyses to mitigate overpressure events.
3/4.4.2.2	S/RV Low-Low Set Function	3.3.6.3	Yes-3	A minimum number of S/RVs is assumed in the containment loading safety analysis.

UNIT 1 IMPROVED TECHNICAL SPECIFICATIONS

SURVEILLANCE REQUIREMENTS

----------NOTE----------
When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided feedwater and main turbine high water level trip capability is maintained.

SURVEILLANCE		FREQUENCY
SR 3.3.2.2.1	Perform CHANNEL FUNCTIONAL TEST.	92 days
SR 3.3.2.2.2	Perform CHANNEL CALIBRATION. The Allowable Value shall be $\leq$ 56.5 inches.	18 months
SR 3.3.2.2.3	Perform LOGIC SYSTEM FUNCTIONAL TEST including valve actuation.	18 months

3.3 INSTRUMENTATION

3.3.3.1 Post Accident Monitoring (PAM) Instrumentation

LCO 3.3.3.1 The PAM instrumentation for each Function in Table 3.3.3.1-1 shall be OPERABLE.

APPLICABILITY: MODES 1 and 2.

ACTIONS

----------NOTES----------
1. LCO 3.0.4 is not applicable.

2. Separate Condition entry is allowed for each Function.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Functions with one required channel inoperable.	A.1 Restore required channel to OPERABLE status.	30 days
B. Required Action and associated Completion Time of Condition A not met.	B.1 Initiate action in accordance with Specification 5.6.7.	Immediately
C. One or more Functions with two or more required channels inoperable.	C.1 Restore all but one required channel to OPERABLE status.	7 days

(continued)

3.3 INSTRUMENTATION

3.3.8.1 Loss of Power (LOP) Instrumentation

LCO 3.3.8.1 The LOP instrumentation for each Function in Table 3.3.8.1-1 shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3,
When the associated diesel generator (DG) is required to be OPERABLE by LCO 3.8.2, "AC Sources — Shutdown."

ACTIONS

---NOTE---
Separate Condition entry is allowed for each channel.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more channels inoperable for Functions 1 and 2.	A.1 Restore channel to OPERABLE status.	1 hour
B. One or more channels inoperable for Function 3.	B.1 Verify voltage on associated 4.16 kV bus is $\geq$ 3825 V.	Once per hour
C. Required Action and associated Completion Time not met.	C.1 Declare associated DG inoperable.	Immediately

SURVEILLANCE REQUIREMENTS

----------NOTE----------

1. Refer to Table 3.3.8.1-1 to determine which SRs apply for each LOP Function.

2. When a 4.16 kV Emergency Bus Undervoltage channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the associated Function maintains DG initiation capability (for Functions 1 and 2) and annunciation capability (for Function 3).

SURVEILLANCE		FREQUENCY
SR 3.3.8.1.1	Perform CHANNEL CHECK.	12 hours
SR 3.3.8.1.2	Perform CHANNEL FUNCTIONAL TEST.	31 days
SR 3.3.8.1.3	Perform CHANNEL CALIBRATION.	18 months
SR 3.3.8.1.4	Perform LOGIC SYSTEM FUNCTIONAL TEST.	18 months

Table 3.3.8.1-1 (page 1 of 1)
Loss of Power Instrumentation

FUNCTION	REQUIRED CHANNELS PER BUS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. 4.16 kV Emergency Bus Undervoltage (Loss of Voltage)			
a. Bus Undervoltage	2	SR 3.3.8.1.2 SR 3.3.8.1.3 SR 3.3.8.1.4	≥ 2800 V
b. Time Delay	2	SR 3.3.8.1.2 SR 3.3.8.1.3 SR 3.3.8.1.4	≤ 6.5 seconds
2. 4.16 kV Emergency Bus Undervoltage (Degraded Voltage)			
a. Bus Undervoltage	2	SR 3.3.8.1.2 SR 3.3.8.1.3 SR 3.3.8.1.4	≥ 3280 V
b. Time Delay	2	SR 3.3.8.1.2 SR 3.3.8.1.3 SR 3.3.8.1.4	≤ 21.5 seconds
3. 4.16 kV Emergency Bus Undervoltage (Annunciation)			
a. Bus Undervoltage	1	SR 3.3.8.1.1 SR 3.3.8.1.2 SR 3.3.8.1.3 SR 3.3.8.1.4	≥ 3825 V
b. Time Delay	1	SR 3.3.8.1.2 SR 3.3.8.1.3 SR 3.3.8.1.4	≤ 60 seconds

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.1.1	Verify correct breaker alignment and indicated power availability for each required offsite circuit.	7 days
SR 3.8.1.2	----------NOTES---------- 1. Performance of SR 3.8.1.5 satisfies this SR. 2. All DG starts may be preceded by an engine prelube period and followed by a warmup period prior to loading. 3. A modified DG start involving idling and gradual acceleration to synchronous speed may be used for this SR as recommended by the manufacturer. When modified start procedures are not used, the time, voltage, and frequency tolerances of SR 3.8.1.5.a must be met. 4. For the swing DG, a single test will satisfy this Surveillance for both units, using the starting circuitry of Unit 1 and synchronized to 4160 V bus 1F for one periodic test, and the starting circuitry of Unit 2 and synchronized to 4160 V bus 2F during the next periodic test. 5. DG loadings may include gradual loading as recommended by the manufacturer. 6. Starting transients above the upper voltage limit do not invalidate this test.	(continued)

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.8.1.2	NOTES (continued) 7. Momentary transients outside the load range do not invalidate this test. 8. This Surveillance shall be conducted on only one DG at a time. --- Verify each DG: a. Starts from standby conditions and achieves steady state voltage ≥ 3740 V and ≤ 4243 V and frequency ≥ 58.8 Hz and ≤ 61.2 Hz; and b. Operates for ≥ 60 minutes at a load ≥ 1710 kW and ≤ 2000 kW.	31 days
SR 3.8.1.3	Verify each day tank contains ≥ 900 gallons of fuel oil.	31 days
SR 3.8.1.4	Check for and remove accumulated water from each day tank.	184 days

(continued)

3.8 ELECTRICAL POWER SYSTEMS

3.8.2 AC Sources — Shutdown

LCO 3.8.2 The following AC electrical power sources shall be OPERABLE:

a. One qualified circuit connected between the offsite transmission network and the onsite Unit 1 Class 1E AC electrical power distribution subsystem(s) required by LCO 3.8.8, "Distribution Systems — Shutdown;"

b. One Unit 1 diesel generator (DG) capable of supplying one subsystem of the onsite Unit 1 Class 1E AC electrical power distribution subsystem(s) required by LCO 3.8.8;

c. One qualified circuit connected between the offsite transmission network and the onsite Unit 2 Class 1E AC electrical power distribution subsystem(s) needed to support the Unit 2 Standby Gas Treatment (SGT) subsystem required by LCO 3.6.4.3, "SGT System;" and

d. One Unit 2 DG capable of supplying the Unit 2 SGT subsystem required by LCO 3.6.4.3.

APPLICABILITY: MODES 4 and 5,
During movement of irradiated fuel assemblies in the secondary containment.

3.8 ELECTRICAL POWER SYSTEMS

3.8.7 Distribution Systems — Operating

LCO 3.8.7 The following AC and DC electrical power distribution subsystems shall be OPERABLE:

a. Unit 1 AC and DC electrical power distribution subsystems comprised of:

1. 4160 V essential buses 1E, 1F, and 1G;
2. 600 V essential buses 1C and 1D;
3. 120/208 V essential cabinets 1A and 1B;
4. 120/208 V instrument buses 1A and 1B;
5. 125/250 V DC station service buses 1A and 1B;
6. DG DC electrical power distribution subsystems; and

b. Unit 2 AC and DC electrical power distribution subsystems needed to support equipment required to be OPERABLE by LCO 3.6.4.3, "Standby Gas Treatment (SGT) System," and LCO 3.8.1, "AC Sources—Operating."

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required Unit 2 AC or DC electrical power distribution subsystems inoperable.	A.1 Restore required Unit 2 AC and DC subsystem(s) to OPERABLE status.	7 days
B. One or more (Unit 1 or swing bus) DG DC electrical power distribution subsystems inoperable.	B.1 Restore DG DC electrical power distribution subsystem to OPERABLE status.	12 hours AND 16 hours from discovery of failure to meet LCO 3.8.7.a

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. One or more (Unit 1 or swing bus) AC electrical power distribution subsystems inoperable.	C.1	Restore AC electrical power distribution subsystem to OPERABLE status.	8 hours AND 16 hours from discovery of failure to meet LCO 3.8.7.a
D. One Unit 1 station service DC electrical power distribution subsystem inoperable.	D.1	Restore Unit 1 station service DC electrical power distribution subsystem to OPERABLE status.	2 hours AND 16 hours from discovery of failure to meet LCO 3.8.7.a
E. Required Action and associated Completion Time of Condition A, B, C, or D not met.	E.1 AND E.2	Be in MODE 3. Be in MODE 4.	12 hours 36 hours
F. Two or more electrical power distribution subsystems inoperable that result in a loss of function.	F.1	Enter LCO 3.0.3.	Immediately

5.0 ADMINISTRATIVE CONTROLS

5.1 Responsibility

5.1.1 The Nuclear Plant General Manager shall provide direct executive oversight over all aspects of Plant Hatch.

5.1.2 The Assistant General Manager-Plant Operations (AGM-PO) shall be responsible for overall unit operation, except for the Radiological Environmental Monitoring Program as described below and for delegation in writing of the succession of this responsibility during his absence. Certain plant support functions shall be the responsibility of the Assistant General Manager-Plant Support (AGM-PS).

5.1.3 The Nuclear Plant General Manager or his designee shall be responsible for the Radiological Environmental Monitoring Program and for the writing of the Annual Radiological Environmental Operating Report.

5.1.4 Each of the individuals in Specification 5.1.1 through Specification 5.1.3 is responsible for the accuracy of the procedures needed to implement his responsibilities.

5.1.5 The Superintendent of Shift (SOS) shall be responsible for the control room command function. During any absence of the SOS from the control room while either unit is in MODE 1, 2, or 3, an individual with an active Senior Reactor Operator (SRO) license shall be designated to assume the control room command function. During any absence of the SOS from the control room while both units are in MODE 4 or 5, an individual with an active SRO license or Reactor Operator license shall be designated to assume the control room command function.

5.0 ADMINISTRATIVE CONTROLS

5.2 Organization

5.2.1 Onsite and Offsite Organizations

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

a. Lines of authority, responsibility, and communication shall be defined and established throughout highest management levels, intermediate levels, and all operating organization positions. These relationships shall be documented and updated, as appropriate, in organization charts, functional descriptions of departmental responsibilities and relationships, and job descriptions for key personnel positions, or in equivalent forms of documentation. These requirements shall be documented in the Plant Hatch Unit 1 updated FSAR;

b. The Assistant General Manager - Plant Operations (AGM-PO) shall be responsible for overall safe operation of the plant and shall have control over those onsite activities necessary for safe operation and maintenance of the plant;

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

d. The individuals who train the operating staff, carry out health physics, or perform quality assurance functions may report to the appropriate onsite manager; however, these individuals shall have sufficient organizational freedom to ensure their independence from operating pressures.

5.2.2 Unit Staff

The unit staff organization shall include the following:

a. A total of three plant equipment operators (PEOs) for the two units is required in all conditions. At least one of

(continued)

5.2 Organization

5.2.2 Unit Staff

a. (continued)

the required PEOs shall be assigned to each reactor containing fuel.

b. At least one licensed Reactor Operator (RO) shall be present in the control room for each unit that contains fuel in the reactor. In addition, while the unit is in MODE 1, 2, or 3, at least one licensed Senior Reactor Operator (SRO) shall be present in the control room.

c. The minimum shift crew composition shall be in accordance with 10 CFR 50.54(m)(2)(i). Shift crew composition may be less than the minimum requirement of 10 CFR 50.54(m)(2)(i) and 5.2.2.a for a period of time not to exceed 2 hours in order to accommodate unexpected absence of on duty shift crew members provided immediate action is taken to restore the shift crew composition to within the minimum requirements.

d. An individual qualified to implement radiation protection procedures shall be on site when fuel is in the reactor. The position may be vacant for not more than 2 hours, in order to provide for unexpected absence, provided immediate action is taken to fill the required position.

e. Administrative procedures shall be developed and implemented to limit the working hours of unit staff who perform safety related functions.

Adequate shift coverage shall be maintained without routine heavy use of overtime. The objective shall be to have operating personnel work a nominal 40 hour week while the unit is operating. However, in the event that unforeseen problems require substantial amounts of overtime to be used, or during extended periods of shutdown for refueling, major maintenance, or major plant modification, on a temporary basis the following guidelines shall be followed:

1. An individual should not be permitted to work more than 16 hours straight, excluding shift turnover time;

(continued)

5.2 Organization

5.2.2 Unit Staff

e. (continued)

2. An individual should not be permitted to work more than 16 hours in any 24 hour period, nor more than 24 hours in any 48 hour period, nor more than 72 hours in any 7 day period, all excluding shift turnover time;

3. A break of at least 8 hours should be allowed between work periods, including shift turnover time;

4. Except during extended shutdown periods, the use of overtime should be considered on an individual basis and not for the entire staff on a shift.

Any deviation from the above guidelines shall be authorized by the AGM-PO, Assistant General Manager-Plant Support (AGM-PS), or by higher levels of management, in accordance with established procedures and with documentation of the basis for granting the deviation.

Controls shall be included in the procedures such that individual overtime shall be reviewed monthly by the AGM-PO, AGM-PS, or designee to ensure that excessive hours have not been assigned. Routine deviation from the above guidelines is not authorized.

f. The Operations Manager shall hold an active or inactive SRO license.

g. The Shift Technical Advisor (STA) shall provide advisory technical support to the Shift Supervisor (SS) in the areas of thermal hydraulics, reactor engineering, and plant analysis with regard to the safe operation of the unit. In addition, the STA shall meet the qualifications specified by the Commission Policy Statement on Engineering Expertise on Shift.

5.6 Reporting Requirements (continued)

5.6.5 CORE OPERATING LIMITS REPORT (COLR)

a. Core operating limits shall be established prior to each reload cycle, or prior to any remaining portion of a reload cycle, and shall be documented in the COLR for the following:

1) Control Rod Block Instrumentation - Rod Block Monitor for Specification 3.3.2.1.

2) The Average Planar Linear Heat Generation Rate for Specification 3.2.1.

3) The Minimum Critical Power Ratio for Specifications 3.2.2 and 3.3.2.1.

b. The analytical methods used to determine the core operating limits shall be those previously reviewed and approved by the NRC, specifically those described in the following documents:

1) NEDE-24011-P-A, "General Electric Standard Application for Reactor Fuel," (applicable amendment specified in the COLR).

2) "Safety Evaluation by the Office of Nuclear Reactor Regulation Supporting Amendment No. 157 to Facility Operating License DPR-57," dated September 12, 1988.

c. The core operating limits shall be determined such that all specified acceptable fuel design limits will be met.

d. The COLR, including any mid-cycle revisions or supplements, shall be provided upon issuance for each reload cycle to the NRC.

5.6.6 Reactor Coolant System (RCS) PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR)

a. RCS pressure and temperature limits for heatup, cooldown, low temperature operation, criticality, and hydrostatic testing as well as heatup and cooldown rates shall be

(continued)

5.6 Reporting Requirements (continued)

5.6.6 Reactor Coolant System (RCS) PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR)

a. (continued)

established and documented in the PTLR for LCO 3.4.9, "RCS Pressure and Temperature (P/T) Limits."

b. The analytical methods used to determine the RCS pressure and temperature limits shall be determined in accordance with Regulatory Guide 1.99.

c. The PTLR shall be provided to the NRC upon issuance for each reactor vessel fluency period and for any revision or supplement thereto.

5.6.7 Post Accident Monitoring (PAM) Instrumentation Report

When a report is required by LCO 3.3.3.1, "Post Accident Monitoring (PAM) Instrumentation," a report shall be submitted within the following 14 days. The report shall outline the preplanned alternate method of monitoring, the cause of the inoperability, and the plans and schedule for restoring the instrumentation channels of the Function to OPERABLE status.

UNIT 1 IMPROVED BASES

BASES

LCO

12. RHR Service Water Flow (continued)

primary indication used by the operator during an accident. Therefore, the PAM specification deals specifically with this portion of the instrument channel.

APPLICABILITY

The PAM instrumentation LCO is applicable in MODES 1 and 2. These variables are related to the diagnosis and preplanned actions required to mitigate DBAs. The applicable DBAs are assumed to occur in MODES 1 and 2. In MODES 3, 4, and 5, plant conditions are such that the likelihood of an event that would require PAM instrumentation is extremely low; therefore, PAM instrumentation is not required to be OPERABLE in these MODES.

ACTIONS

Note 1 has been added to the ACTIONS to exclude the MODE change restriction of LCO 3.0.4. This exception allows entry into the applicable MODE while relying on the ACTIONS even though the ACTIONS may eventually require plant shutdown. This exception is acceptable due to the passive function of the instruments, the operator's ability to diagnose an accident using alternative instruments and methods, and the low probability of an event requiring these instruments.

Note 2 has been provided to modify the ACTIONS related to PAM instrumentation channels. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable PAM instrumentation channels provide appropriate compensatory measures for separate Functions. As such, a Note has been provided that allows separate Condition entry for each inoperable PAM Function.

(continued)

BASES

ACTIONS (continued)

A.1

When one or more Functions have one required channel that is inoperable, the required inoperable channel must be restored to OPERABLE status within 30 days. The 30 day Completion Time is based on operating experience and takes into account the remaining OPERABLE channels (or, in the case of a Function that has only one required channel, other non-Regulatory Guide 1.97 instrument channels to monitor the Function), the passive nature of the instrument (no critical automatic action is assumed to occur from these instruments), and the low probability of an event requiring PAM instrumentation during this interval.

B.1

If a channel has not been restored to OPERABLE status in 30 days, this Required Action specifies initiation of action in accordance with Specification 5.6.7, which requires a written report to be submitted to the NRC. This report discusses the results of the root cause evaluation of the inoperability and identifies proposed restorative actions. This action is appropriate in lieu of a shutdown requirement, since alternative actions are identified before loss of functional capability, and given the likelihood of plant conditions that would require information provided by this instrumentation.

C.1

When one or more Functions have two or more required channels that are inoperable (i.e., two channels inoperable in the same Function), all but one channel in the Function should be restored to OPERABLE status within 7 days. The Completion Time of 7 days is based on the relatively low probability of an event requiring PAM instrument operation and the availability of alternate means to obtain the required information. Continuous operation with two required channels inoperable in a Function is not acceptable because the alternate indications may not fully meet all performance qualification requirements applied to the PAM instrumentation. Therefore, requiring restoration of one inoperable channel of the Function limits the risk that the

(continued)

B 3.3 INSTRUMENTATION

B 3.3.8.1 Loss of Power (LOP) Instrumentation

BASES

BACKGROUND

Successful operation of the required safety functions of the Emergency Core Cooling Systems (ECCS) is dependent upon the availability of adequate power sources for energizing the various components such as pump motors, motor operated valves, and the associated control components. The LOP instrumentation monitors the 4.16 kV emergency buses. Offsite power is the preferred source of power for the 4.16 kV emergency buses. If the monitors determine that insufficient power is available, the buses are disconnected from the offsite power sources and connected to the onsite diesel generator (DG) power sources.

Each 4.16 kV emergency bus has its own independent LOP instrumentation and associated trip logic. The voltage for each bus is monitored at two levels: 4.16 kV Emergency Bus Undervoltage Loss of Voltage and Degraded Voltage, however, only the Loss of Voltage Function is part of this LCO. The Loss of Voltage Function causes various bus transfers and disconnects and is monitored by two undervoltage relays for each emergency bus, whose outputs are arranged in a two-out-of-two logic configuration for all affected components except the DGs. The DG start logic configuration is one-out-of-two (Ref. 1). The channels include electronic equipment (e.g., trip units) that compares measured input signals with pre-established setpoints. When the setpoint is exceeded, the channel output relay actuates, which then outputs a LOP trip signal to the trip logic.

Each 4.16 kV emergency bus has its own independent LOP alarm instrumentation to provide an anticipatory alarm and the initiation of corrective measures to restore emergency bus voltages. The alarms are set higher than the LOP relays. The alarm setpoints are approximately midway between the calculated minimum expected voltage and the calculated minimum required voltage, based on the maximum expected operating; i.e., non-LOCA, load conditions. The alarm setpoints signify that adequate voltage is available for normal operations. The LOP anticipatory alarms provide a total time delay of 60 seconds to reduce the possibility of nuisance alarms, while permitting prompt detection of potential low voltage conditions.

(continued)

BASES

BACKGROUND (continued)

Each 4.16 kV emergency bus has a dedicated low voltage annunciator fed by two relays and their associated time delays. The logic for the annunciation function is arranged in a one-out-of-two configuration.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The LOP instrumentation is required for Engineered Safety Features to function in any accident with a loss of offsite power. The required channels of LOP instrumentation ensure that the ECCS and other assumed systems powered from the DGs, provide plant protection in the event of any of the Reference 2, 3, and 4 analyzed accidents in which a loss of offsite power is assumed. The initiation of the DGs on loss of offsite power, and subsequent initiation of the ECCS, ensure that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Accident analyses credit the loading of the DG based on the loss of offsite power during a loss of coolant accident. The diesel starting and loading times have been included in the delay time associated with each safety system component requiring DG supplied power following a loss of offsite power.

The LOP alarm instrumentation is required to initiate manual actions to restore the 4.16 kV emergency bus voltages or to initiate a plant shutdown. The required channels of LOP alarm instrumentation ensure the initiation of manual actions to protect the ECCS and other assumed systems from degraded voltage without initiating an unnecessary automatic disconnect from the preferred offsite power source. The occurrence of an undervoltage degraded voltage condition credits the manual actions to mitigate the condition and ensure plant safety is maintained.

The LOP instrumentation satisfies Criterion 3 of the NRC Policy Statement (Ref. 5), except that credit is taken for manual actions.

The OPERABILITY of the LOP instrumentation is dependent upon the OPERABILITY of the individual instrumentation channel Functions specified in Table 3.3.8.1-1. Each Function must have a required number of OPERABLE channels per 4.16 kV emergency bus, with their setpoints within the specified Allowable Values. A channel is inoperable if its actual trip setpoint is not within its required Allowable Value. The setpoint is calibrated consistent with applicable procedures (nominal trip setpoint).

The Allowable Values are specified for the 4.16 kV Emergency Bus Undervoltage Function. Nominal trip setpoints are specified in the setpoint calculations. The nominal setpoints are selected, based on engineering judgment, to ensure that the setpoints do not exceed the Allowable Value between CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within the Allowable Value, is acceptable. Trip setpoints are those predetermined values of output and time delay at which an action should take place. The setpoints are compared to the actual process parameter (e.g., degraded voltage), and when the measured output value of the process

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

parameter exceeds the setpoint and time delay, the associated device (e.g., trip relay) changes state.

The 4.16 kV undervoltage degraded voltage trip setpoints were determined in accordance with the NRC staff positions contained in an NRC letter dated June 2, 1977, except that manual actions are credited for restoring bus voltages or initiating a plant shutdown in the range of 78.8 to 92% of 4.16 kV. The undervoltage degraded voltage setpoint represents a point on the inverse time characteristic curve for the relay. The anticipatory alarm setpoints are approximately midway between the calculated minimum expected voltage and the calculated minimum required voltage, based on maximum expected operating; i.e., non-LOCA, conditions.

The Specific Applicable Safety Analyses, LCO, and Applicability discussions are listed below on Function by Function basis.

1. 4.16 kV Emergency Bus Undervoltage (Loss of Voltage)

Loss of voltage on a 4.16 kV emergency bus indicates that offsite power may be completely lost to the respective emergency bus and is unable to supply sufficient power for proper operation of the applicable equipment. Therefore, the power supply to the bus is transferred from offsite power to DG power when the voltage on the bus drops below the Loss of Voltage Function Allowable Values (loss of voltage with a short time delay). This ensures that adequate power will be available to the required equipment.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The Bus Undervoltage Allowable Values are low enough to prevent inadvertent power supply transfer, but high enough to ensure that power is available to the required equipment. The Time Delay Allowable Values are long enough to provide time for the offsite power supply to recover to normal voltages, but short enough to ensure that power is available to the required equipment.

Two channels of 4.16 kV Emergency Bus Undervoltage (Loss of Voltage) Function per associated emergency bus are only required to be OPERABLE when the associated DG is required to be OPERABLE to ensure that no single instrument failure can preclude the DG function. (Two channels input to each of the three DGs.) Refer to LCO 3.8.1, "AC Sources — Operating," and 3.8.2, "AC Sources — Shutdown," for Applicability Bases for the DGs.

2. 4.16 kV Emergency Bus Undervoltage (Degraded Voltage)

A reduced voltage condition on a 4.16 kV emergency bus indicates that, while offsite power may not be completely lost to the respective emergency bus, available power may be insufficient for starting large ECCS motors without risking damage to the motors that could disable the ECCS Function. Therefore, power supply to the bus is transferred from offsite power to onsite DG power when the voltage on the bus drops below the Degraded Voltage Function Allowable Values (degraded voltage with a time delay). This ensures that adequate power will be available to the required equipment.

The Bus Undervoltage Allowable Values are low enough to prevent inadvertent power supply transfer, but high enough to ensure that sufficient power is available to the large ECCS motors. The Time Delay Allowable Values are long enough for the offsite power supply to usually recover. This minimizes the potential that short duration disturbances will adversely impact the availability of the offsite power supply. Manual actions are credited in the range of 78.8 to 92% of 4.16 kV to restore bus voltages or to initiate a plant shutdown. The range specified for manual actions indicates that sufficient power is available to the large ECCS motors; however, sufficient voltage for equipment at lower voltages required for LOCA conditions may not be available.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Two channels of 4.16 kV Emergency Bus Undervoltage (Degraded Voltage) Function per associated bus are only required to be OPERABLE when the associated DG is required to be OPERABLE to ensure that no single instrument failure can preclude the DG function. (Two channels input to each of the three emergency buses and DGs.) Refer to LCO 3.8.1 and LCO 3.8.2 for Applicability Bases for the DGs.

3. 4.16 kV Emergency Bus Undervoltage (Anticipatory Alarm)

A reduced voltage condition on a 4.16 kV emergency bus indicates that, while offsite power is adequate for normal operating conditions, available power may be marginal for some equipment required for LOCA conditions. Therefore, the anticipatory alarms actuate when the 4.16 kV bus voltages approach the minimum required voltage for normal; i.e., non-LOCA conditions. This ensures that manual actions will be initiated to restore the bus voltages or to initiate a plant shutdown.

One channel of 4.16 kV Emergency Bus Undervoltage (Anticipatory Alarm) Function per associated bus are only required to be OPERABLE when the associated DG is required to be OPERABLE. (Two channels input to each of the three emergency buses.)

ACTIONS

A Note has been provided to modify the ACTIONS related to LOP instrumentation channels. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition, discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable LOP instrumentation channels provide appropriate compensatory measures for separate inoperable channels. As such, a Note has been provided that allows separate Condition entry for each inoperable LOP instrumentation channel.

(continued)

BASES

ACTIONS

A.1

With one or more channels of Function 1 or 2 inoperable, the Function is not capable of performing the intended function. Therefore, only 1 hour is allowed to restore the inoperable channel to OPERABLE status. The Required Action does not allow placing a channel in trip since this action will result in a DG initiation. |

(continued)

BASES

ACTIONS

A.1 (continued)

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. The 1 hour Completion Time is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

B.1

Each 4.16 kV bus has a dedicated annunciator fed by two relays and associated time delays in a one-out-of-two logic configuration. Only one relay and its associated time delay is required to be OPERABLE. Therefore, the loss of the required relay or time delay renders Function 3 incapable of performing the intended function. Since the intended function is to alert personnel to a lowering voltage condition and the voltage reading is available for each bus on the control room front panels, the Required Action is verification of the voltage to be above the annunciator setpoint (nominal) hourly.

C.1

If any Required Action and associated Completion Time are not met, the associated Function is not capable of performing the intended function. Therefore, the associated DG(s) is declared inoperable immediately. This requires entry into applicable Conditions and Required Actions of LCO 3.8.1 and LCO 3.8.2, which provide appropriate actions for the inoperable DG(s).

SURVEILLANCE REQUIREMENTS

As noted at the beginning of the SRs, the SRs for each LOP instrumentation Function are located in the SRs column of Table 3.3.8.1-1. The Surveillances are modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the associated Function maintains DG initiation capability (for Functions 1 and 2) and annunciation capability (for Function 3). Functions 1 and 2 maintain DG initiation capability provided two DGs can be initiated by the Function. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken.

SR 3.3.8.1.1

Performance of the CHANNEL CHECK once every 12 hours ensures that a gross failure of instrumentation or a failure of annunciation has not occurred. A CHANNEL CHECK is defined for Function 3 to be a comparison of the annunciator status to the bus voltage and an annunciator test confirming the annunciator is capable of lighting and sounding. A CHANNEL CHECK will detect gross channel failure or an annunciator failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

If a channel is outside the match criteria, it may be an indication that the instrument has drifted outside its limit.

The frequency is based upon operating experience that demonstrates channel failure is rare. Thus, performance of the CHANNEL CHECK ensures that undetected outright channel or annunciator failure is limited to 12 hours. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with channels required by the LCO.

SR 3.3.8.1.2

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

The Frequency of 31 days is based on operating experience with regard to channel OPERABILITY and drift, which demonstrates that failure of more than one channel of a given Function in any 31 day interval is a rare event.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.8.1.3

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations, consistent with the plant specific setpoint methodology.

The Frequency is based upon the assumption of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.8.1.4

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required actuation logic for a specific channel. The system functional testing performed in LCO 3.8.1 and LCO 3.8.2 overlaps this Surveillance to provide complete testing of the assumed safety functions.

The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at the 18 month Frequency.

REFERENCES

1. FSAR, Section 8.4.

2. FSAR, Section 4.8.

3. FSAR, Section 6.5.

4. FSAR, Chapter 14.

5. NRC No. 93-102, "Final Policy Statement on Technical Specification Improvements," July 23, 1993.

B 3.3 INSTRUMENTATION

B 3.3.8.2 Reactor Protection System (RPS) Electric Power Monitoring

BASES

BACKGROUND

RPS Electric Power Monitoring System is provided to isolate the RPS bus from the motor generator (MG) set or an alternate power supply in the event of overvoltage, undervoltage, or underfrequency. This system protects the loads connected to the RPS bus against unacceptable voltage and frequency conditions (Ref. 1) and forms an important part of the primary success path of the essential safety circuits. Some of the essential equipment powered from the RPS buses includes the RPS logic, scram solenoids, and various valve isolation logic (e.g., residual heat removal shutdown cooling).

RPS electric power monitoring assembly will detect any abnormal high or low voltage or low frequency condition in the outputs of the two MG sets or the alternate power supply and will de-energize its respective RPS bus, thereby causing all safety functions normally powered by this bus to de-energize.

In the event of failure of an RPS Electric Power Monitoring System (e.g., both inseries electric power monitoring assemblies), the RPS loads may experience significant effects from the unregulated power supply. Deviation from the nominal conditions can potentially cause damage to the scram solenoids and other Class 1E devices.

In the event of a low voltage condition, the scram solenoids can chatter and potentially lose their pneumatic control capability, resulting in a loss of primary scram action.

In the event of an overvoltage condition for an extended period of time, the RPS logic relays and scram solenoids, as well as the main steam isolation valve (MSIV) solenoids, may experience a voltage higher than their design voltage. If the overvoltage condition persists for an extended time period, it may cause equipment degradation and the loss of plant safety function.

Two redundant Class 1E circuit breakers are connected in series between each RPS bus and its MG set, and between each RPS bus and its alternate power supply. Each of these

(continued)

BASES

BACKGROUND (continued)

A description of the Unit 2 onsite power sources is provided in the Bases for Unit 2 LCO 3.8.1.

APPLICABLE SAFETY ANALYSES

The initial conditions of DBA and transient analyses in the FSAR, Chapters 5 and 6 (Refs. 3 and 4, respectively) and Chapter 14 (Ref. 5), assume ESF systems are OPERABLE. The AC electrical power sources are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System (RCS), and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.5, Emergency Core Cooling System (ECCS) and Reactor Core Isolation Cooling (RCIC) System; and Section 3.6, Containment Systems.

The OPERABILITY of the AC electrical power sources is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This includes maintaining the onsite or offsite AC sources OPERABLE during accident conditions in the event of:

a. An assumed loss of all offsite power sources or all onsite AC power sources; and

b. A postulated worst case single failure.

AC sources satisfy Criterion 3 of the NRC Policy Statement (Ref. 14).

LCO

Two qualified circuits between the offsite transmission network and the onsite Unit 1 Class 1E Distribution System and three separate and independent DGs (1A, 1B, and 1C) ensure availability of the required power to shut down the reactor and maintain it in a safe shutdown condition after an anticipated operational occurrence (AOO) or a postulated DBA. In addition, since some components required by Unit 1 are powered from Unit 2 sources (i.e., Standby Gas Treatment (SGT) System), one qualified circuit between the offsite transmission network and the onsite Unit 2 Class 1E Distribution System, and one Unit 2 DG (2A or 2C), capable of supplying power to the required Unit 2 SGT subsystem, must also be OPERABLE.

(continued)

BASES

LCO (continued)

Qualified offsite circuits are those that are described in the FSAR, and are part of the licensing basis for the unit. Each offsite circuit must be capable of maintaining rated frequency and voltage, and accepting required loads during an accident, while connected to the ESF buses. For the purpose of this LCO, each Unit 1 offsite circuit consists of incoming breaker and disconnect to the respective 1C and 1D SATs, the 1C and 1D transformers, and the respective circuit path including feeder breakers to 4.16 kV ESF buses. (However, for design purposes, the offsite circuit excludes the feeder breakers to each 4.16 kV ESF bus). Feeder breakers from each circuit to the 1F ESF bus are required to be OPERABLE; however, only one feeder breaker per bus to the 1E and 1G ESF buses is required to be OPERABLE, but they must be from different SATs (e.g., 1E feeder breaker from the 1C SAT and the 1G feeder breaker from the 1D SAT). With 1E and 1G ESF buses both fed from one SAT (normal line up is both buses fed from 1D SAT), both feeder breakers to each of these ESF buses are required to be OPERABLE. The Unit 2 offsite circuit also consists of the incoming breaker and disconnect to the 4.16 kV ESF buses required to be OPERABLE to provide power to the Unit 2 equipment required by LCO 3.6.4.3.

Each DG must be capable of starting, accelerating to rated frequency and voltage, and connecting to its respective ESF bus on detection of bus undervoltage. This sequence must be accomplished within 12 seconds. Each DG must also be capable of accepting required loads within the assumed loading sequence intervals, and must continue to operate until offsite power can be restored to the ESF buses. These capabilities are required to be met from a variety of initial conditions, such as DG in standby with the engine hot and DG in standby with the engine at ambient condition.

Proper sequencing of loads, including tripping of nonessential loads, is a required function for DG OPERABILITY.

The AC sources must be separate and independent (to the extent possible) (Ref. 1) of other AC sources. For the DGs, the separation and independence are complete. For the offsite AC sources, the separation and independence are to the extent practical. A circuit may be connected to more than one ESF bus, with automatic transfer capability to the

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.2 (continued)

The normal 31 day Frequency for SR 3.8.1.2 is consistent with Regulatory Guide 1.108 (Ref. 10). This Frequency provides adequate assurance of DG OPERABILITY, while minimizing degradation resulting from testing.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.18

This Surveillance demonstrates that the DG starting independence has not been compromised. Also, this Surveillance demonstrates that each engine can achieve proper speed within the specified time when the DGs are started simultaneously. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil continuously circulated and temperature maintained consistent with manufacturer recommendations. It is permissible to place all three DGs in test simultaneously, for the performance of this Surveillance.

The 10 year Frequency is consistent with the recommendations of Regulatory Guide 1.108 (Ref. 10). This SR is modified by a Note. The reason for the Note is to minimize wear on the DG during testing.

SR 3.8.1.19

With the exception of this Surveillance, all other Surveillances of this Specification (SR 3.8.1.1 through SR 3.8.1.18) are applied only to the Unit 1 DG and offsite circuits, and swing DG. This Surveillance is provided to direct that the appropriate Surveillances for the required Unit 2 DG and offsite circuit are governed by the Unit 2 Technical Specifications. Performance of the applicable Unit 2 Surveillances will satisfy both any Unit 2 requirements, as well as satisfying this Unit 1 Surveillance requirement. Two exceptions are noted to the Unit 2 SRs of LCO 3.8.1. SR 3.8.1.6 is excepted since only one Unit 2 circuit is required by the Unit 1 Specification. Therefore, there is not necessarily a second circuit to transfer to. SR 3.8.1.18 is excepted since there is only one Unit 2 DG required by the Unit 1 Specification. Therefore, there are not necessarily multiple DGs for simultaneous start.

The Frequency required by the applicable Unit 2 SR also governs performance of that SR for both Units.

(continued)

BASES

REFERENCES

1. 10 CFR 50, Appendix A, GDC 17.

2. FSAR, Sections 8.3 and 8.4.

(continued)

BASES

REFERENCES (continued)

3. FSAR, Chapter 5.

4. FSAR, Chapter 6.

5. FSAR, Chapter 14.

6. Regulatory Guide 1.93, December 1974.

7. Generic Letter 84-15.

8. 10 CFR 50, Appendix A, GDC 18.

9. Regulatory Guide 1.9, March 1971.

10. Regulatory Guide 1.108, August 1977.

11. Regulatory Guide 1.137, October 1979.

12. IEEE Standard 387 - 1984.

13. IEEE Standard 308 - 1980.

14. NRC No. 93-102, "Final Policy Statement on Technical Specification Improvements," July 23, 1993.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.2 AC Sources -- Shutdown

BASES

BACKGROUND

A description of the AC sources is provided in the Bases for LCO 3.8.1, "AC Sources -- Operating."

APPLICABLE SAFETY ANALYSES

The OPERABILITY of the minimum AC sources during MODES 4 and 5 and during movement of irradiated fuel assemblies in the secondary containment ensures that:

a. The facility can be maintained in the shutdown or refueling condition for extended periods;

b. Sufficient instrumentation and control capability is available for monitoring and maintaining the unit status; and

c. Adequate AC electrical power is provided to mitigate events postulated during shutdown, such as an inadvertent draindown of the vessel or a fuel handling accident.

In general, when the unit is shut down the Technical Specifications requirements ensure that the unit has the capability to mitigate the consequences of postulated accidents. However, assuming a single failure and concurrent loss of all offsite or loss of all onsite power is not required. The rationale for this is based on the fact that many Design Basis Accidents (DBAs) that are analyzed in MODES 1, 2, and 3 have no specific analyses in MODES 4 and 5. Postulated worst case bounding events are deemed not credible in MODES 4 and 5 because the energy contained within the reactor pressure boundary, reactor coolant temperature and pressure, and corresponding stresses result in the probabilities of occurrences significantly reduced or eliminated, and minimal consequences. These deviations from DBA analysis assumptions and design requirements during shutdown conditions are allowed by the LCO for required systems.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

Table 3.8.6-1 (continued)

electron transfer capability. The Category C limit for voltage is based on IEEE-450 (Ref. 3), which states that a cell voltage of 2.07 V or below, under float conditions and not caused by elevated temperature of the cell, indicates internal cell problems and may require cell replacement. The Category C limit for float charging current is characteristic of a battery that is approaching a fully charged condition. The limit for each battery is specified in Reference 4.

REFERENCES

1. FSAR, Chapters 5 and 6.

2. FSAR, Chapter 14.

3. IEEE Standard 450 - 1987.

4. Technical Requirements Manual.

5. NRC No. 93-102, "Final Policy Statement on Technical Specification Improvements," July 23, 1993.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.7 Distribution Systems — Operating

BASES

BACKGROUND

The onsite Class 1E AC and DC electrical power distribution system is divided into redundant and independent AC and DC electrical power distribution subsystems.

The primary AC distribution system consists of three 4.16 kV Engineered Safety Feature (ESF) buses each having an offsite source of power as well as a dedicated onsite diesel generator (DG) source. Each 4.16 kV ESF bus is normally connected to a normal source startup auxiliary transformer (SAT) (1D). During a loss of the normal offsite power source to the 4.16 kV ESF buses, the alternate supply breaker from SAT 1C attempts to close. If all offsite sources are unavailable, the onsite emergency DGs supply power to the 4.16 kV ESF buses.

The secondary plant distribution system includes 600 VAC emergency buses 1C and 1D and associated load centers, and transformers.

There are two independent 125/250 VDC station service electrical power distribution subsystems and three independent 125 VDC DG electrical power distribution subsystems that support the necessary power for ESF functions.

A description of the Unit 2 AC and DC electrical power distribution system is provided in the Bases for Unit 2 LCO 3.8.7, "Distribution System—Operating."

The list of required Unit 1 distribution buses is presented in LCO 3.8.7.

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the FSAR, Chapters 5 and 6 (Ref. 1) and Chapter 14 (Ref. 2), assume ESF systems are OPERABLE. The AC and DC electrical power distribution systems are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

necessary power to ESF systems so that the fuel, Reactor Coolant System, and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.5, Emergency Core Cooling Systems (ECCS) and Reactor Core Isolation Cooling (RCIC) System; and Section 3.6 Containment Systems.

The OPERABILITY of the AC and DC electrical power distribution subsystems is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This includes maintaining distribution systems OPERABLE during accident conditions in the event of:

a. An assumed loss of all offsite power sources or all onsite AC electrical power sources; and

b. A postulated worst case single failure.

The AC and DC electrical power distribution system satisfies Criterion 3 of the NRC Policy Statement (Ref. 4).

LCO

The Unit 1 AC and DC electrical power distribution subsystems are required to be OPERABLE. The required Unit 1 electrical power distribution subsystems listed in LCO 3.8.7 ensure the availability of AC and DC electrical power for the systems required to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence (AOO) or a postulated DBA.

Should one or more buses not listed in LCO 3.8.7 become inoperable due to a failure not affecting the OPERABILITY of a bus listed in LCO 3.8.7 (e.g., a breaker supplying a single MCC faults open), the individual loads on the bus would be considered inoperable, and the appropriate Conditions and Required

(continued)

BASES

LCO (continued)

Actions of the LCOs governing the individual loads would be entered. If however, one or more of these buses is inoperable due to a failure also affecting the OPERABILITY of a bus listed in LCO 3.8.7 (e.g., loss of a 4.16 kV ESF bus, which results in de-energization of all buses powered from the 4.16 kV ESF bus), the Conditions and Required Actions of the LCO for the individual loads are not required to be entered, since LCO 3.0.6 allows this exception (i.e., the loads are inoperable due to the inoperability of a support system governed by a Technical Specification; the 4.16 kV ESF bus). In addition, since some components required by Unit 1 receive power through Unit 2 electrical power distribution subsystems (e.g., Standby Gas Treatment (SGT) System), the Unit 2 AC and DC electrical power distribution subsystems needed to support the required equipment must also be OPERABLE.

Maintaining the Division 1 and 2 and swing bus AC and DC electrical power distribution subsystems OPERABLE ensures that the redundancy incorporated into the design of ESF is not defeated. Therefore, a single failure within any system or within the electrical power distribution subsystems will not prevent safe shutdown of the reactor.

The AC electrical power distribution subsystem requires the associated buses and electrical circuits to be energized to their proper voltages. OPERABLE DC electrical power distribution subsystems require the associated buses to be energized to their proper voltage from either the associated battery or charger.

In addition, tie breakers between redundant safety related AC and DC power distribution subsystems, if they exist, must be open. This prevents any electrical malfunction in any power distribution subsystem from propagating to the redundant subsystem, which could cause the failure of a redundant subsystem and a loss of essential safety function(s). If any tie breakers are closed, the electrical power distribution subsystem which is not being powered from its normal source (i.e., it is being powered from its redundant electrical power distribution subsystem) is considered inoperable. This applies to the onsite, safety related, redundant electrical power distribution subsystems. It does not, however, preclude redundant Class 1E 4.16 kV ESF buses from being powered from the same offsite circuit.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3 8.7.1

This Surveillance verifies that the AC and DC electrical power distribution systems are functioning properly, with the correct circuit breaker alignment. The correct breaker alignment ensures the appropriate separation and independence of the electrical buses are maintained, and the appropriate voltage is available to each required bus. The verification of proper voltage availability on the buses ensures that the required voltage is readily available for motive as well as control functions for critical system loads connected to these buses. The 7 day Frequency takes into account the redundant capability of the AC and DC electrical power distribution subsystems, and other indications available in the control room that alert the operator to subsystem malfunctions.

REFERENCES

1. FSAR, Chapters 5 and 6.

2. FSAR, Chapter 14.

3. Regulatory Guide 1.93, December 1974.

4. NRC No. 93-102, "Final Policy Statement on Technical Specification Improvements," July 23, 1993.

BASES (continued)

BASES (continued)

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.8 Distribution Systems — Shutdown

BASES

BACKGROUND

A description of the AC and DC electrical power distribution system is provided in the Bases for LCO 3.8.7, "Distribution Systems — Operating."

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident and transient analyses in the FSAR, Chapters 5 and 6 (Ref. 1) and Chapter 14 (Ref. 2), assume Engineered Safety Feature (ESF) systems are OPERABLE. The AC and DC electrical power distribution systems are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System, and containment design limits are not exceeded.

The OPERABILITY of the AC and DC electrical power distribution system is consistent with the initial assumptions of the accident analyses and the requirements for the supported systems' OPERABILITY.

The OPERABILITY of the minimum AC and DC electrical power sources and associated power distribution subsystems during MODES 4 and 5 and during movement of irradiated fuel assemblies in the secondary containment ensures that:

a. The facility can be maintained in the shutdown or refueling condition for extended periods;

b. Sufficient instrumentation and control capability is available for monitoring and maintaining the unit status; and

c. Adequate power is provided to mitigate events postulated during shutdown, such as an inadvertent draindown of the vessel or a fuel handling accident.

The AC and DC electrical power distribution systems satisfy Criterion 3 of the NRC Policy Statement (Ref. 3).

(continued)

UNIT 1 MARKUP OF CURRENT TECHNICAL SPECIFICATIONS AND DISCUSSION OF CHANGES

A.1 proposed LCO 3.3.8.1 statement

Table 3.3.8.1-1 (C)

~~TABLE 3.2-12~~

LOP

~~DEGRADED STATION VOLTAGE PROTECTION~~ INSTRUMENTATION (A.1)

LA.1

Ref. No. (a)	Instrument (b)	Required Operable Channels	Channels Required To Trip	~~Trip Setting~~ Allowable Value (LA.1)	Action to be Taken If the Number of Required Operable Channels is Not Met
LCO 3.3.8.1		LCO 3.3.8.1			
1	4.16 kv Emergency Bus Undervoltage Relay (Loss of Voltage Condition)	2/Bus	2/Bus	greater than or equal to 2800 volts. At 2800 volts time delay will be less than or equal to 6.5 sec.	(c) Actions A, B, and C (C)
2	4.16 kv Emergency Bus Undervoltage Relay (Degraded Voltage Condition)	2/Bus	2/Bus	greater than or equal to 3280 volts. At 3280 volts time delay will be less than or equal to 21.5 sec.	(c) (C)

proposed LOP Function 3 (M.4)

~~NOTES FOR TABLE 3.2-12~~

a. The column entitled "Ref. No." is only for convenience so that a one-to-one relationship can be established between items in Table 3.2-12 and items in Table 4.2-12. (A.1)

Applicability

b. This instrumentation is required to be operable during reactor startup, power operation, and hot shutdown. proposed 2nd Applicability (M.1)

c.1. With the number of operable channels one less than the required operable channels, operation may proceed until performance of the next required instrument functional test provided a trip signal is placed in the LOSP lock-out relay logic for the applicable inoperable channel. (A.2) within 1 hour (M.2) — ACTION A

c.2. One instrument channel may be inoperable for up to 6 hours to perform required surveillances prior to entering other applicable actions.

proposed ACTION B (M.1)

proposed ACTION C (L.1)

(C)

NOTE to Surveillance Requirements

Justification 3.3.8.1

~~TABLE 4.2-12~~

LOP

~~DEGRADED STATION VOLTAGE PROTECTION~~ INSTRUMENTATION

A.1

M.4

proposed LOP Function 3

Ref. No. (a)	Instrument (b)	SR 3.3.8.1.1 Instrument Check Minimum Frequency	SR 3.3.8.1.2 Instrument Functional Test Minimum Frequency	SR 3.3.8.1.3 Instrument Calibration Minimum Frequency
1	4.16 Kv Emergency Bus Undervoltage Relay (Loss of Voltage Condition)	N/A	Once/month	~~Once/operating cycle~~ A.3 → 18 months
2	4.16 Kv Emergency Bus Undervoltage Relay (Degraded Voltage Condition)	N/A	Once/month	~~Once/operating cycle~~

M.3

proposed SR 3.3.8.1.4

C

NOTES FOR TABLE 4.2-12

a. The column entitled "Ref. No." is only for convenience so that a one-to-one relationship can be established between items in Table 3.2-12 and items in Table 4.2-12. A.1

b. Surveillance of this instrumentation is required during reactor startup, power operation, and hot shutdown. proposed 2nd Applicability M.1

Applicability

HATCH - UNIT 1

3.2-49a

Amendment No. 88, 186

2 of 4

Specification 3.3.8.1

LIMITING CONDITIONS FOR OPERATION	SURVEILLANCE REQUIREMENTS
See Discussion of Changes for ITS: 3.5.1, ECCS-Operating, in Section 3.5	4.9.A.6. Emergency 250 Volt DC to 600 Volt AC Inverters (Continued) b. Once every scheduled refueling outage, the emergency 250-volt DC/600-volt AC inverters shall be subjected to a load test to demonstrate operational readiness.
3.9.A.7. Logic Systems The following logic systems shall be operable:	4.9.A.7. Logic Systems The logic systems shall be tested in the manner and frequency as follows:
a. The common accident signal logic system is operable.	a. Each division of the common accident signal logic system shall be tested every scheduled refueling outage to demonstrate that it will function on actuation of the ECCS to provide an automatic start signal to all 3 diesel generators. Each diesel generator shall operate on standby ≥ 5 minutes.
b. The undervoltage relays and supporting system are operable.	b.1. Once every 18 months during shutdown, the conditions under which the undervoltage logic system is required shall be simulated with an undervoltage on each start bus to demonstrate that the emergency busses are deenergized, and that the diesel generators will start, energize the emergency busses with permanently connected loads in ≤ 12 seconds, energize the auto-connected shutdown loads through the load sequencer, operate for ≥ 5 minutes while the diesle generators are loaded with the shutdown loads, and achieve and maintain a steady-state voltage of 4160 ± 420 volts and a steady-state frequency of 60 ± 1.2 Hz. The testing of the undervoltage logic shall also demonstrate the operability of the 4160-volt load shedding and auto bus transfer circuits, and that the subsequent loading is in accordance with design requirements (± 10% of its design interval). The simulations shall test both the degraded voltage and the loss of offsite power relays. (C)
See Discussion of Changes for ITS: 3.8.1, in Section 3.8	SR 3.3.8.1.4

LIMITING CONDITIONS FOR OPERATION	SURVEILLANCE REQUIREMENTS
3.9.A.7. Logic Systems (Continued)	4.9.A.7. Logic Systems (Continued)
	2. Deleted
	3. Deleted
c. The common accident signal logic system, and undervoltage relays and supporting system are operable.	c.1. Once every 18 months during shutdown, each diesel generator shall be demonstrated operable by simulating a loss of offsite power in conjunction with an accident test signal and verifying: de-energization of the emergency buses and load shedding from the emergency buses; and the diesel starts on the auto-start signal with permanently connected loads in ≤ 12 seconds, energizes the auto-connected shutdown (emergency) loads through the load sequencer, operates for ≥ 5 minutes while its generator is loaded with the emergency loads, and achieves and maintains a steady-state voltage of 4160 ± 420 volts and a steady-state frequency of 60 ± 1.2 Hz.
	2. The undervoltage relays for the start buses shall be calibrated ~~annually~~ for trip and reset voltages and the measurements recorded.
	3. Verify, once per 18 months during shutdown, that all diesel generator trips, except engine overspeed, low lube oil pressure, and generator differential, are automatically bypassed upon loss of voltage on the emergency bus concurrent with an ECCS actuation signal.

See Discussion of Changes for ITS: 3.8.1, in Section 3.8

△G | SR 3.3.8.1.3

A.3 — 18 months — LA.1

DISCUSSION OF CHANGES
ITS: SECTION 3.3.8.1 - LOSS OF POWER INSTRUMENTATION

ADMINISTRATIVE

A.1 Reformatting and renumbering requirements is in accordance with the BWR Standard Technical Specifications, NUREG 1433. As a result, the Technical Specifications should be more readily readable, and therefore understandable by plant operators as well as other users. During this reformatting and renumbering process, no technical changes (either actual or interpretational) to the Technical Specifications were made unless they were identified and justified. During this process, the listing of the various tables has been deleted since it is found in the Table of Contents at the beginning of the document. A new LCO statement has been added to describe the channel requirements. I

A.2 The requirement for performing the Instrument Functional Test is included in the proposed SR 3.3.8.1.2. It is possible that the test would not be able to be performed with an inoperable channel, and a plant shutdown would be required due to the inability to perform the required surveillance. However, this restriction on continued operation need not be specified as an Action (as is the case in existing Action a); it exists inherently as a result of the Instrument Functional Test requirement. In addition, the channel is not allowed to be placed in trip in the ITS (see comments M.2), thus this statement does not apply. Since no change in operation, requirements or intent is made, the proposed revision to eliminate a specific restriction of continued operation is considered administrative. I

A.3 The Frequency of "once/operating cycle" has been changed to "18 months". Since the current operating cycle is normally 18 months, this change is considered administrative. Also, the annual requirement to calibrate this instrument in the AC Sources specification (4.9.A.7.2.c) has been changed to 18 months, since this Frequency is already allowed in the Instrumentation Section (Table 4.1-12). As such, this change is considered administrative.

TECHNICAL CHANGE - MORE RESTRICTIVE

M.1 An additional Applicability has been added, requiring the instruments to be OPERABLE when the associated diesel generators (DGs) are required to be OPERABLE by LCO 3.8.2, AC Sources—Shutdown. This essentially adds a MODE 4 and 5 applicability when the DGs are required in these MODES. This is consistent with the BWR Standard Technical Specifications, NUREG 1433 and is an additional restriction on plant operation.

M.2 The allowance to place the LOSP lock-out relay in trip has been changed to require restoration of the entire channel. Placing the LOSP lock-out relay in trip does not result in all components affected by the channel receiving a trip signal. In addition, a finite Completion Time of 1 hour

TECHNICAL CHANGE - MORE RESTRICTIVE

M.2 (continued)

has been provided to place an inoperable channel in trip. Currently, no Completion Time is provided. This change is consistent with the BWR Standard Technical Specifications, NUREG 1433 and is an additional restriction on plant operation.

M.3 An additional Surveillance Requirement has been added (proposed SR 3.3.8.1.4) to perform a LOGIC SYSTEM FUNCTIONAL TEST (LSFT) once per 18 months. This will ensure that the entire logic is functioning properly similar to the current LSFT already required for the ECCS instrumentation (LCO 3.3.5.1), which also provides a DG start signal. This is consistent with the BWR Standard Technical Specifications, NUREG 1433 and is an additional restriction on plant operation.

M.4 To satisfy Criterion 3 of the NRC Policy Statement, Hatch credits manual actions in the range of 78.8 to 92% of 4.16 kV. Entry into this range is annunciated. The range specified for manual actions indicates that sufficient power is available to the large ECCS motors; however, sufficient voltage for equipment required for LOCA conditions may not be available at lower voltages. The required channels of LOP annunciation instrumentation ensure the initiation of manual actions to protect the ECCS and other assumed systems from degraded voltage without initiating an unnecessary automatic disconnect from the preferred offsite power source. The LOP anticipatory annunciators provide a total time delay of 60 seconds to reduce the possibility of nuisance annunciators while permitting prompt detection of potential low voltage conditions. Since Hatch takes credit for the annunciators, they have been added to Table 3.3.8.1-1. Additionally, new LCO CONDITION "B" addressing the annunciation Function has been added and the other CONDITIONS renumbered and amended as necessary to account for the annunciation. Appropriate SRs are defined for the annunciator bus undervoltage relays and the associated time delays.

TECHNICAL CHANGE - LESS RESTRICTIVE

"Generic"

LA.1 System design and operational details have been relocated to the Bases and procedures. Trip setpoints are an operational detail that is not directly related to the operability of the instrumentation. The Allowable Value is the required limitation for these parameters and these values are retained in Table 3.3.8.1-1. Details relating to system design and operation (e.g., description of action of instrumentation) are also unnecessary in the LCO and have been relocated to the Bases and procedures. The design features and system operation are also described in the FSAR. In

TECHNICAL CHANGE - MORE RESTRICTIVE

LA.1
(continued)

addition, requirements to record values during Surveillance Requirements has been relocated to plant procedures. Changes to the Bases will be controlled by the provisions of the proposed Bases Control Process described in Chapter 5 of the Technical Specifications. Changes to the FSAR and procedures will be controlled by the provisions of 10 CFR 50.59.

"Specific"

L.1 An ACTION has been added (proposed ACTION C) to require declaring the DG inoperable (and taking the appropriate actions in the associated DG Specification) if a channel is not restored within 1 hour. Currently, the ACTIONS appear to require a Specification 3.0.3 entry, which would result in an immediate shutdown. Since Functions 1 and 2 instrumentation provide a start signal for the DGs (i.e., it supports DG OPERABILITY), the appropriate action would be to declare the DG inoperable. The current requirements are overly restrictive, in that if the diesel were inoperable for other reasons, a 72 hour restoration time is provided; yet currently if an instrument is inoperable but the diesel is otherwise fully OPERABLE, an immediate shutdown is required. The ACTION also applies to Function 3 but would only be entered if both the annunciation and voltage indication were inoperable.

Specification 3.8.1

LIMITING CONDITIONS FOR OPERATION	SURVEILLANCE REQUIREMENTS
3.9.A.2. Standby AC Power Supply (Diesel Generators 1A, 1B, and 1C) (Continued)	4.9.A.2. Standby AC Power Supply (Diesel Generators 1A, 1B, and 1C) (Continued)
a. Operability The diesel generator itself and its auxiliaries are operable. (LA.1)	a. Operability 1. Each diesel generator shall be manually started and loaded to demonstrate operational readiness ~~in accordance with the frequency specified in Table 4.9.A-1 on a Staggered Test Basis~~.* (SR 3.8.1.2) Verify that each diesel starts from ambient condition, gradually load the generator to 1710-2000 kw** and operate for ≥ 60 minutes. A steady-state voltage of 4160 ± 420 volts and a steady-state frequency of 60 ± 1.2 Hz will be maintained. Verify the pressure in both diesel air start receivers to be ≥ 225 psig. (LA.6, L.2, L.1, C, M.10, L.1, proposed Note 1, A.2, proposed Notes 1, 3, 5, and 8 to SR 3.8.1.2, proposed Note 2 to SR 3.8.1.2)
	See Discussion of Changes for ITS 3.8.3, in this Section.
	2. At least once per 184 days, each diesel generator shall be started and verified to reach synchronous speed in ≤ 12 seconds, loaded to an indicated 2250-2400 kw** for 1A and 1C and 2360-2425 kw** for 1B in ≤ 120 seconds,* and operated for ≥ 60 minutes. The test will verify the diesel generator will achieve and maintain a steady-state voltage of 4160 ± 420 volts and a steady-state frequency of 60 ± 1.2 Hz.* (SR 3.8.1.5, proposed Note 4, A.2, B, proposed Note 2, L.3, M.10)

Note 4 to SR 3.8.1.2: *For the 1B (swing) diesel, a single test will satisfy the requirements for Unit 1 Specification 4.9.A.2.a.1 and Unit 2 Specification 4.8.1.1.2.a.4, with the diesel connected to one unit's emergency bus for one periodic test and connected to the emergency bus in the other unit during the next periodic test.

Note 5 to SR 3.8.1.5: A single 6-month (184-day) test for the 1B diesel will satisfy the requirements for Unit 1 Specification 4.9.A.2.a.2 and Unit 2 Specification 4.8.1.1.2.b. The 6-month test will be performed using the starting circuitry and emergency bus from one unit. The next 6-month test will be performed using the starting circuitry and emergency bus from the other unit.

Note 7 to SR 3.8.1.2 and Note 3 to SR 3.8.1.5: **Momentary variations outside this band shall not invalidate the test.

Specification 3.8.1

~~Table 4.9-1~~

~~DIESEL GENERATOR TEST SCHEDULE~~

Number of Failures In Last 20 Valid Tests*	Test Frequency
≤ 1	At least once per 31 days.
≥ 2	At least once per 7 days.

DELETED

*Criteria for determining number of failures and number of valid tests shall be in accordance with Regulatory Position C.2.e of Regulatory Guide 1.108, Revision 1, August 1977, except that only the last 20 tests are used, and are determined on a per diesel basis.

C

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TECHNICAL CHANGE - MORE RESTRICTIVE
(continued)

M.8 Deleted.

M.9 Deleted.

M.10 The existing tolerance for voltage (± 10%) is being restricted to -10%, +2%. Reducing the allowable overvoltage is based on the acceptable overvoltage limits of equipment on the 600 V buses.

TECHNICAL CHANGE - LESS RESTRICTIVE

"Generic"

LA.1 The details of what constitutes OPERABILITY, system design and purpose, have been relocated to the Bases. The design features are also described in the FSAR. Thus, the LCO has been written to tell what is needed, but not in excessive detail. Changes to the Bases will be controlled by the provisions of the proposed Bases Control Process in Chapter 5 of the Technical Specifications. Changes to the FSAR will be controlled by the provisions of 10 CFR 50.59.

LA.2 This Surveillance has been deleted in the proposed Technical Specifications. Procedural controls on DG inspections recommended by the manufacturer are sufficient to ensure the DG receives the necessary inspections. Removal of this Surveillance from the Technical Specifications will have no effect on DG OPERABILITY. Changes to the procedures will be controlled by the provisions of 10 CFR 50.59.

LA.3 The specific component name of the single largest load need not be detailed within the Technical Specifications. The value of the load, as well as the component itself, are specifically detailed in the Bases, as well as the FSAR. Changes to the Bases will be controlled by the Bases Control Process described in Chapter 5 of the Technical Specifications. Changes to the FSAR are controlled by 10 CFR 50.59. The reference to the single largest load within the Technical Specifications is not necessary to adequately present the requirement. Similarly, the load value for the auto-connected loads is removed from the proposed Technical Specifications. Any change to the loads placed on the DG will be controlled by 10 CFR 50.59 (a design change is required to change the loads).

TECHNICAL CHANGE - LESS RESTRICTIVE
(continued)

LA.4 When the OPERABILITY of a system or component has been affected by repair, maintenance, or replacement of a component, post maintenance testing is required to demonstrate OPERABILITY of the system or component. Explicit post maintenance Surveillance Requirements have, therefore, been deleted from the Specifications. Entry into the applicable modes without performing this post maintenance testing also continues to be allowed as discussed in the Bases for SR 3.0.1.

LA.5 The purpose of this SR is inherent in the manner in which the test is performed and is described in the Bases for SR 3.8.1.9 (load shedding) and SR 3.8.1.6 (auto bus transfer). Therefore, the description has been relocated to the Bases. Changes to the Bases will be controlled by the provision of the proposed Bases Control Process in Chapter 5 of the Technical Specifications.

LA.6 The diesel generator accelerated test frequency requirements are relocated in their current licensing bases form to plant procedures, leaving the Technical Specifications periodic surveillance frequency as 31 days. A plant procedure implements the current Technical Specifications requirements for accelerated test frequency, as well as the requirements and responsibilities for tracking emergency DG failures for the determination and reporting of reaching trigger values specified in NUMARC 87-00. These requirements are more restrictive than those specified in NUREG 1433.

"Specific"

L.1 Note 2 to SR 3.8.1.2, Note 1 to SR 3.8.1.5 and the Note to SR 3.8.1.18 have been added to allow a prelube prior to starting the DG. DG starts without prior engine prelube create unnecessary engine wear, thereby reducing overall reliability. The engine prelube does not result in an enhanced start performance which could mask the engine's ability to start in accident conditions without a prelube. In addition, Note 2 and SR 3.8.1.2 also allow a gradual DG warmup. This portion of the Note is allowed currently, because no startup time is specified in the current surveillance.

L.2 The intent of a requirement for staggered testing is to increase reliability of the component/system being tested. A number of studies have been performed which have demonstrated that staggered testing has negligible impact on component reliability. These analytical and subjective analyses have determined that staggered testing 1) is operationally difficult, 2) has negligible impact on component reliability, 3) is not as significant as initially thought, 4) has no impact on failure frequency, 5) introduces additional stress on components such as DGs potentially causing increased component failure rates and component wearout, 6) results in reduced redundancy during testing, and 7)

TECHNICAL CHANGE - LESS RESTRICTIVE
(continued)

L.10 The proposed Required Actions B.3.1 and B.3.2 provide an allowance to avoid unnecessary testing of the OPERABLE DG when a DG is declared inoperable. This change is consistent with that approved on the River Bend Station docket (Amendment No. 64, dated 9/29/92). The intent of the actions is to confirm no common-mode failure has rendered more than one DG inoperable. This assurance can be ascertained in many cases by means other than the existing requirement for a DG start. If an assessment can determine no common-mode failure exists on the remaining OPERABLE DGs, the proposal allows for not requiring an unnecessary DG start. Minimizing DG starts is recommended to avoid unnecessary diesel wear, thereby enhancing overall DG reliability (refer to Generic Letter 84-15). In addition, the requirement to load the DG has been deleted. Demonstrating the DG start capability is sufficient to provide the added assurance that the DG is still OPERABLE.

L.11 The proposed Required Actions A.2 and B.2 provide an allowance to avoid an immediate forced shutdown when a DG or offsite circuit is inoperable concurrent with a required "feature" (i.e., system, subsystem, component) inoperability. This change is consistent with that approved on the River Bend Station docket (Amendment No. 64, dated 9/29/92). With these concurrent inoperabilities, certain events that are required by GDC 17 to be capable of being mitigated, will not be able to be mitigated. These events involve accidents which are coupled with a complete loss of all offsite or DG power. However, certain combinations of inoperable components may allow for satisfactory compensatory actions or have been justified for some allowed restoration time. By allowing "features" associated with the inoperable offsite circuit DG to be declared inoperable, the appropriate ACTIONS can be taken. This can potentially eliminate unnecessary forced shutdowns, and the associated risk of plant transient, while maintaining ACTION provisions previously provided concerning the specific circumstances.

LIMITING CONDITIONS FOR OPERATION	SURVEILLANCE REQUIREMENTS
3.9.A.3. 125/250 Volt DC Emergency Power System (Plant Batteries 1A and 1B) Both 125/250 volt plant batteries (1A and 1B) shall be operable and shall have an operable battery charger and ventilation system available for each.	4.9.A.3. 125/250 Volt DC Emergency Power System (Plant Batteries 1A and 1B) a. Weekly Surveillance Every week the specific gravity and the voltage of the pilot cell and overall battery voltage shall be measured and recorded. Each 125 volt battery shall have a minimum of 105 volts at the battery terminals to be considered operable. b. Monthly Surveillance Every month measurements shall be made of voltage of each cell to the nearest 0.1 volt and the specific gravity of each cell. These measurements shall be recorded. Liquid level shall be checked visually. c. Refueling Outage Surveillance During each scheduled refueling outage, the batteries shall be subjected to a rated load discharge test. The specific gravity and voltage of each cell shall be determined after the discharge and recorded.
4. Emergency 4160 Volt Buses (1E, 1F, and 1G) The emergency 4160 volt buses (1E, 1F, and 1G) shall be energized and operable.	4. Emergency 4160 Volt Buses (1E, 1F, and 1G) The emergency 4160 volt buses (1E, 1F, and 1G) shall be monitored to the extent that they are shown to be ready and capable of transmitting the emergency load.
5. Emergency 600 Volt Buses (1C and 1D) The emergency 600 volt buses (1C and 1D) shall be energized and operable.	5. Emergency 600 Volt Buses (1C and 1D) The emergency 600 volt buses (1C and 1D) shall be monitored to the extent that they are shown to be ready and capable of transmitting the emergency load.
6. Emergency 250 Volt DC to 600 Volt AC Inverters The emergency 250 volt DC to 600 volt AC inverters shall be energized and operable.	6. Emergency 250 Volt DC to 600 Volt AC Inverters a. The emergency 250 volt DC/600 volt AC inverters shall be monitored to the extent that they are shown to be ready and capable of transmitting the emergency load.

See Discussion of Changes for ITS: 3.8.4 in this section.

See Discussion of Changes for ITS: 3.8.6 in this section.

LCO 3.8.7.a

LA.1

SR 3.8.7.1

M.2

LCO 3.8.7.a

A.4

M.1

LA.1

SR 3.8.7.1

M.2

Proposed LCO 3.8.7.b and DC portion of LCO 3.8.7.a

See Discussion of Changes for ITS: 3.5.1 in Section 3.5.

DISCUSSION OF CHANGES
ITS: SECTION 3.8.7 - DISTRIBUTION SYSTEMS—OPERATING

ADMINISTRATIVE

A.1 The term "buses" has been changed to "subsystems" since the buses are grouped in this manner (e.g., 600 V 1C receives power normally from 4160 V bus 1E; thus, they are part of the same subsystem). No technical changes are made.

A.2 This general paragraph has been deleted since it provides general guidance that is discussed in other parts of the Technical Specifications or Bases.

A.3 This requirement is being deleted since another ACTION (ACTION F) provides direction for various interrelationships between the Distribution buses. The ACTION will require a shutdown if two 4160 V or two 600 V buses are concurrently inoperable. Therefore, this change is administrative.

A.4 The Unit 1 120/280 V essential cabinets and instrument buses governed by the definition of OPERABILITY for the Unit 1 equipment powered by these buses have been added to Specification 3.8.7. This is consistent with the implementation of the current Unit 2 licensing basis.

TECHNICAL CHANGE - MORE RESTRICTIVE

M.1 Certain equipment needed to meet Unit 1 accident analysis is powered from the Unit 2 AC and DC Distribution System. Currently, the Unit 2 Distribution buses are required since the Unit 1 definition of OPERABILITY requires the necessary electrical power to be OPERABLE. To make the Technical Specifications more user friendly, the Unit 2 required buses have been added, similar to the already required Unit 1 buses. Since Unit 2 buses are now described, the current LCO and ACTIONS for Unit 1 buses have been modified to explicitly use the unit designator. An ACTION has also been provided (proposed ACTION A) to limit the out of service time of a Unit 2 bus to 7 days. This is consistent with the current time allowed in the individual system LCO. These changes, are administrative only; however, due to the addition of proposed ACTION F, an inoperable Unit 2 bus concurrent with an inoperable Unit 1 bus can result in a LCO 3.0.3 entry. Currently, an LCO 3.0.3 entry is not required when in this condition.

In addition, the Unit 1 station service DC distribution subsystems, which are governed by the definition of OPERABILITY for the Unit 1 equipment powered by these buses have also been moved here for clarity. Thus, proposed ACTION D has been provided to limit the out of service time for a Unit 1 Station Service DC distribution subsystem to 2 hours, consistent with the guidance of Regulatory Guide 1.93.

In addition nother Completion Time (16 hours from discovery of failure to meet LCO 3.8.7.a) is added, as described in comment M.5, to establish a maximum time allowed to not meet the Unit 1 bus requirements. Also, SRs are now explicitly required for the Unit 1 DC and the Unit 2 AC and DC buses. Therefore, this change, is considered more restrictive on plant operations.

TECHNICAL CHANGE - LESS RESTRICTIVE

"Generic"

LA.1 The details relating to system design and purpose, and the meaning of "OPERABLE" (e.g., "energized") have been relocated to the Bases. The design features and system operation are also described in the FSAR. Changes to the Bases will be controlled by the provisions of the proposed Bases Control Process in Chapter 5 of the Technical Specifications. Changes to the FSAR will be controlled by the provisions of 10 CFR 50.59.

"Specific"

L.1 The time to reach MODE 4, Cold Shutdown, has been extended from 24 hours to 36 hours. This provides the necessary time to shut down and cool down the plant in a controlled and orderly manner that is within the capabilities of the unit, assuming the minimum required equipment is OPERABLE. This extra time reduces the potential for a unit upset that could challenge safety systems. This time is consistent with the BWR Standard Technical Specifications, NUREG 1433.

L.2 ACTION B has been added to provide a 12 hour restoration time, prior to requiring a unit shutdown, if a DG DC bus were inoperable. Currently, if the DG DC bus were inoperable, the associated DG and the offsite circuit would be inoperable (due to loss of control power). This now requires an immediate shutdown. The new time, 12 hours, is consistent with the time provided in Regulatory Guide 1.93 and the BWR Standard Technical Specifications for when a DG and offsite circuit are concurrently inoperable. Another Completion Time (16 hours from discovery of failure to meet LCO 3.8.7.a) has been added, as described in comment M.5, to establish a maximum time allowed to not meet the Unit 1 bus requirements. This limits the total time of any Unit 1 bus inoperability to 16 hours.

INSERT 1 for ITS 5.1

The Superintendent of Shift (SOS) shall be responsible for the control room command function. During any absence of the SOS from the control room while either unit is in MODE 1, 2, or 3, an individual with an active Senior Reactor Operator (SRO) license shall be designated to assume the control room command function. During any absence of the SOS from the control room while both units are in MODE 4 or 5, an individual with an active SRO license or Reactor Operator license shall be designated to assume the control room command function.

C

A.18 A.1 A.16 A.12 A.12 A.9

SPECIAL REPORTS

6.9.2. Special reports shall be submitted to the NRC Regional Office within the time period specified and for each activity shown in Table ~~6.9.2-1~~. Special reports for fire protection equipment operating and surveillance requirements shall be submitted, as required, by the Fire Hazards Analysis and its Appendix B requirements.

6.10. RECORD RETENTION

In addition to the applicable record retention requirements of Title 10, Code of Federal Regulations, the following records shall be retained for at least the minimum period indicated.

See Discussion of changes for CTS: 6.10, IN this Section.

6.10.1. The following records shall be retained for at least five years:

a. Records and logs of unit operation covering time interval at each power level.

b. Records and logs of principal maintenance activities, inspections, repair and replacement of principal items of equipment related to nuclear safety.

c. ALL REPORTABLE EVENTS submitted to the Commission.

d. Records of surveillance activities, inspections and calibrations required by these Technical Specifications.

e. Records of changes made to the procedures required by Specification 6.8.1.

f. Records of radioactive shipments.

g. Records of sealed source and fission detector leak tests and results.

h. Records of annual physical inventory of all sealed source material of record.

6.10.2. The following records shall be retained for the duration of the unit Operating License:

a. Records and drawing changes reflecting unit design modifications made to systems and equipment described in the Final Safety Analysis Report.

b. Records of new and irradiated fuel inventory, fuel transfers and assembly burnup histories.

DISCUSSION OF CHANGES
ITS: SECTION 5.6 - REPORTING REQUIREMENTS

TECHNICAL CHANGES - MORE RESTRICTIVE

M.1 The current TS requirement in 6.9.1.5.b to submit an annual report for all challenges to safety/relief valves has been moved to proposed ITS 5.6.1.4 for monthly reports. Since the report is required on a monthly basis instead of the current annual basis, this change is more restrictive in nature.

M.2 This change details the information to be included in the report. These details are necessary to assure the reports are provided with similar content and format for comparison with other plants and with prior reports.

M.3 A new report is required in conjunction with the changes described in Section 3.4 for the reactor coolant system pressure and temperature limits. In addition, requirements are included for methods used to determine such limits and for submitting the report to the NRC.

TECHNICAL CHANGE - LESS RESTRICTIVE

"Generic"

LA.1 The details associated with CTS 6.9.1.1, 6.9.1.2, and 6.9.1.3, "Start-Up Report," are proposed to be relocated to the FSAR. The Start-Up Report provides the NRC a mechanism to review the appropriateness of licensee activities after-the-fact, but provides no regulatory authority once the report is submitted (i.e., no requirement for NRC approval). The Quality Assurance requirements of 10 CFR 50, Appendix B and the Startup Test Program provisions contained in the FSAR provide assurance the listed activities will be adequately performed and that appropriate corrective actions, if required, are taken. The placement of these CTS requirements in the FSAR also ensures that change control is performed in accordance with 10 CFR 50.59.

UNIT 2 IMPROVED TECHNICAL SPECIFICATIONS

3.3 INSTRUMENTATION

3.3.3.1 Post Accident Monitoring (PAM) Instrumentation

LCO 3.3.3.1 The PAM instrumentation for each Function in Table 3.3.3.1-1 shall be OPERABLE.

APPLICABILITY: MODES 1 and 2.

ACTIONS

----------NOTES----------
1. LCO 3.0.4 is not applicable.

2. Separate Condition entry is allowed for each Function.

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or more Functions with one required channel inoperable.	A.1	Restore required channel to OPERABLE status.	30 days
B. Required Action and associated Completion Time of Condition A not met.	B.1	Initiate action in accordance with Specification 5.6.7.	Immediately
C. One or more Functions with two or more required channels inoperable.	C.1	Restore all but one required channel to OPERABLE status.	7 days

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Required Action and associated Completion Time of Condition C not met.	D.1 Enter the Condition referenced in Table 3.3.3.1-1 for the channel.	Immediately
E. As required by Required Action D.1 and referenced in Table 3.3.3.1-1.	E.1 Be in MODE 3.	12 hours
F. As required by Required Action D.1 and referenced in Table 3.3.3.1-1.	F.1 Initiate action in accordance with Specification 5.6.8.	Immediately

SURVEILLANCE REQUIREMENTS

----------NOTES----------

1. These SRs apply to each Function in Table 3.3.3.1-1.

2. When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the other required channel(s) in the associated Function is OPERABLE.

SURVEILLANCE		FREQUENCY
SR 3.3.3.1.1	Perform CHANNEL CHECK.	31 days
SR 3.3.3.1.2	Perform CHANNEL CALIBRATION.	18 months

3.3 INSTRUMENTATION

3.3.8.1 Loss of Power (LOP) Instrumentation

LCO 3.3.8.1 The LOP instrumentation for each Function in Table 3.3.8.1-1 shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3,
When the associated diesel generator (DG) is required to be OPERABLE by LCO 3.8.2, "AC Sources — Shutdown."

ACTIONS

NOTE
Separate Condition entry is allowed for each channel.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more channels inoperable for Functions 1 and 2.	A.1 Restore channel to OPERABLE status.	1 hour
B. One or more channels inoperable for Function 3.	B.1 Verify voltage on associated 4.16 kV bus is $\geq$ 3825 V.	Once per hour
C. Required Action and associated Completion Time not met.	C.1 Declare associated DG inoperable.	Immediately

SURVEILLANCE REQUIREMENTS

NOTE

1. Refer to Table 3.3.8.1-1 to determine which SRs apply for each LOP Function.

2. When a 4.16 kV Emergency Bus Undervoltage channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the associated Function maintains DG initiation capability (for Functions 1 and 2) and annunciation capability (for Function 3).

SURVEILLANCE		FREQUENCY
SR 3.3.8.1.1	Perform CHANNEL CHECK.	12 hours
SR 3.3.8.1.2	Perform CHANNEL FUNCTIONAL TEST.	31 days
SR 3.3.8.1.3	Perform CHANNEL CALIBRATION.	18 months
SR 3.3.8.1.4	Perform LOGIC SYSTEM FUNCTIONAL TEST.	18 months

Table 3.3.8.1-1 (page 1 of 1)
Loss of Power Instrumentation

FUNCTION	REQUIRED CHANNELS PER BUS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. 4.16 kV Emergency Bus Undervoltage (Loss of Voltage)			
a. Bus Undervoltage	2	SR 3.3.8.1.2 SR 3.3.8.1.3 SR 3.3.8.1.4	≥ 2800 V
b. Time Delay	2	SR 3.3.8.1.2 SR 3.3.8.1.3 SR 3.3.8.1.4	≤ 6.5 seconds
2. 4.16 kV Emergency Bus Undervoltage (Degraded Voltage)			
a. Bus Undervoltage	2	SR 3.3.8.1.2 SR 3.3.8.1.3 SR 3.3.8.1.4	≥ 3280 V
b. Time Delay	2	SR 3.3.8.1.2 SR 3.3.8.1.3 SR 3.3.8.1.4	≤ 21.5 seconds
3. 4.16 kV Emergency Bus Undervoltage (Annunciation)			
a. Bus Undervoltage	1	SR 3.3.8.1.1 SR 3.3.8.1.2 SR 3.3.8.1.3 SR 3.3.8.1.4	≥ 3825 V
b. Time Delay	1	SR 3.3.8.1.2 SR 3.3.8.1.3 SR 3.3.8.1.4	≤ 60 seconds

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.1.1	Verify correct breaker alignment and indicated power availability for each required offsite circuit.	7 days
SR 3.8.1.2	----------NOTES---------- 1. Performance of SR 3.8.1.5 satisfies this SR. 2. All DG starts may be preceded by an engine prelube period and followed by a warmup period prior to loading. 3. A modified DG start involving idling and gradual acceleration to synchronous speed may be used for this SR as recommended by the manufacturer. When modified start procedures are not used, the time, voltage, and frequency tolerances of SR 3.8.1.5.a must be met. 4. For the swing DG, a single test will satisfy this Surveillance for both units, using the starting circuitry of Unit 2 and synchronized to 4160 V bus 2F for one periodic test, and the starting circuitry of Unit 1 and synchronized to 4160 V bus 1F during the next periodic test. 5. DG loadings may include gradual loading as recommended by the manufacturer. 6. Starting transients above the upper voltage limit do not invalidate this test.	(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.2	NOTES (continued) 7. Momentary transients outside the load range do not invalidate this test. 8. This Surveillance shall be conducted on only one DG at a time. --- Verify each DG: a. Starts from standby conditions and achieves steady state voltage $\geq$ 3740 V and $\leq$ 4243 V and frequency $\geq$ 58.8 Hz and $\leq$ 61.2 Hz; and b. Operates for $\geq$ 60 minutes at a load $\geq$ 1710 kW and $\leq$ 2000 kW.	31 days
SR 3.8.1.3	Verify each day tank contains $\geq$ 900 gallons of fuel oil.	31 days
SR 3.8.1.4	Check for and remove accumulated water from each day tank.	184 days

(continued)

3.8 ELECTRICAL POWER SYSTEMS

3.8.2 AC Sources — Shutdown

LCO 3.8.2 The following AC electrical power sources shall be OPERABLE:

a. One qualified circuit connected between the offsite transmission network and the onsite Unit 2 Class 1E AC electrical power distribution subsystem(s) required by LCO 3.8.8, "Distribution Systems — Shutdown;"

b. One Unit 2 diesel generator (DG) capable of supplying one subsystem of the onsite Unit 2 Class 1E AC electrical power distribution subsystem(s) required by LCO 3.8.8;

c. One qualified circuit connected between the offsite transmission network and the onsite Unit 1 Class 1E AC electrical power distribution subsystem(s) needed to support the Unit 1 equipment required to be OPERABLE by LCO 3.6.4.9, "Standby Gas Treatment (SGT) System—Refueling," LCO 3.7.4, "Main Control Room Environmental Control (MCREC) System," and LCO 3.7.5, "Control Room Air Conditioning (AC) System;" and

d. One Unit 1 DG capable of supplying one subsystem of each of the Unit 1 equipment required to be OPERABLE by LCO 3.6.4.9, LCO 3.7.4, and LCO 3.7.5.

APPLICABILITY: MODES 4 and 5,
During movement of irradiated fuel assemblies in the Unit 1 secondary containment.

Table 3.8.6-1 (page 1 of 2)
Battery Cell Parameter Requirements

PARAMETER	CATEGORY A: LIMITS FOR EACH DESIGNATED PILOT CELL	CATEGORY B: LIMITS FOR EACH CONNECTED CELL	CATEGORY C: LIMITS FOR EACH CONNECTED CELL
Electrolyte Level	> Minimum level indication mark, and ≤ ¼ inch above maximum level indication mark(a)	> Minimum level indication mark, and ≤ ¼ inch above maximum level indication mark(a)	Above top of plates, and not overflowing
Float Voltage	≥ 2.13 V	≥ 2.13 V	> 2.07 V
Float Charging Current	(b)	(b)	(b)

(a) It is acceptable for the electrolyte level to temporarily increase above the specified maximum level during equalizing charges provided it is not overflowing.

(b) As applicable to each battery.

3.8 ELECTRICAL POWER SYSTEMS

3.8.7 Distribution Systems — Operating

LCO 3.8.7 The following AC and DC electrical power distribution subsystems shall be OPERABLE:

a. Unit 2 AC and DC electrical power distribution subsystems comprised of:

1. 4160 V essential buses 2E, 2F, and 2G;
2. 600 V essential buses 2C and 2D;
3. 120/208 V essential cabinets 2A and 2B;
4. 120/208 V instrument buses 2A and 2B;
5. 125/250 V DC station service buses 2A and 2B;
6. DG DC electrical power distribution subsystems; and

b. Unit 1 AC and DC electrical power distribution subsystems needed to support equipment required to be OPERABLE by LCO 3.6.4.7, "Standby Gas Treatment (SGT) System—Operating," LCO 3.7.4, "Main Control Room Environmental Control (MCREC) System," LCO 3.7.5, "Control Room Air Conditioning (AC) System," and LCO 3.8.1, "AC Sources—Operating."

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required Unit 1 AC or DC electrical power distribution subsystems inoperable.	A.1 Restore required Unit 1 AC and DC subsystem(s) to OPERABLE status.	7 days

(continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One or more (Unit 2 or swing bus) DG DC electrical power distribution subsystems inoperable.	B.1 Restore DG DC electrical power distribution subsystem to OPERABLE status.	12 hours AND 16 hours from discovery of failure to meet LCO 3.8.7.a

(continued)

5.0 ADMINISTRATIVE CONTROLS

5.1 Responsibility

5.1.1 The Nuclear Plant General Manager shall provide direct executive oversight over all aspects of Plant Hatch.

5.1.2 The Assistant General Manager-Plant Operations (AGM-PO) shall be responsible for overall unit operation, except for the Radiological Environmental Monitoring Program as described below and for delegation in writing of the succession of this responsibility during his absence. Certain plant support functions shall be the responsibility of the Assistant General Manager-Plant Support (AGM-PS).

5.1.3 The Nuclear Plant General Manager or his designee shall be responsible for the Radiological Environmental Monitoring Program and for the writing of the Annual Radiological Environmental Operating Report.

5.1.4 Each of the individuals in Specification 5.1.1 through Specification 5.1.3 is responsible for the accuracy of the procedures needed to implement his responsibilities.

5.1.5 The Superintendent of Shift (SOS) shall be responsible for the control room command function. During any absence of the SOS from the control room while either unit is in MODE 1, 2, or 3, an individual with an active Senior Reactor Operator (SRO) license shall be designated to assume the control room command function. During any absence of the SOS from the control room while both units are in MODE 4 or 5, an individual with an active SRO license or Reactor Operator license shall be designated to assume the control room command function.

5.0 ADMINISTRATIVE CONTROLS

5.2 Organization

5.2.1 Onsite and Offsite Organizations

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

a. Lines of authority, responsibility, and communication shall be defined and established throughout highest management levels, intermediate levels, and all operating organization positions. These relationships shall be documented and updated, as appropriate, in organization charts, functional descriptions of departmental responsibilities and relationships, and job descriptions for key personnel positions, or in equivalent forms of documentation. These requirements shall be documented in the Plant Hatch Unit 2 FSAR;

b. The Assistant General Manager-Plant Operations (AGM-PO) shall be responsible for overall safe operation of the plant and shall have control over those onsite activities necessary for safe operation and maintenance of the plant;

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

d. The individuals who train the operating staff, carry out health physics, or perform quality assurance functions may report to the appropriate onsite manager; however, these individuals shall have sufficient organizational freedom to ensure their independence from operating pressures.

5.2.2 Unit Staff

The unit staff organization shall include the following:

a. A total of three plant equipment operators (PEOs) for the two units is required in all conditions. At least one of

(continued)

5.2 Organization

5.2.2 Unit Staff

a. (continued)

the required PEOs shall be assigned to each reactor containing fuel.

b. At least one licensed Reactor Operator (RO) shall be present in the control room for each unit that contains fuel in the reactor. In addition, while the unit is in MODE 1, 2, or 3, at least one licensed Senior Reactor Operator (SRO) shall be present in the control room.

c. The minimum shift crew composition shall be in accordance with 10 CFR 50.54(m)(2)(i). Shift crew composition may be less than the minimum requirement of 10 CFR 50.54(m)(2)(i) and 5.2.2.a for a period of time not to exceed 2 hours in order to accommodate unexpected absence of on duty shift crew members provided immediate action is taken to restore the shift crew composition to within the minimum requirements.

d. An individual qualified to implement radiation protection procedures shall be on site when fuel is in the reactor. The position may be vacant for not more than 2 hours, in order to provide for unexpected absence, provided immediate action is taken to fill the required position.

e. Administrative procedures shall be developed and implemented to limit the working hours of unit staff who perform safety related functions.

Adequate shift coverage shall be maintained without routine heavy use of overtime. The objective shall be to have operating personnel work a nominal 40 hour week while the unit is operating. However, in the event that unforeseen problems require substantial amounts of overtime to be used, or during extended periods of shutdown for refueling, major maintenance, or major plant modification, on a temporary basis the following guidelines shall be followed:

1. An individual should not be permitted to work more than 16 hours straight, excluding shift turnover time;

(continued)

5.2 Organization

5.2.2 Unit Staff (continued)

e. (continued)

2. An individual should not be permitted to work more than 16 hours in any 24 hour period, nor more than 24 hours in any 48 hour period, nor more than 72 hours in any 7 day period, all excluding shift turnover time;

3. A break of at least 8 hours should be allowed between work periods, including shift turnover time;

4. Except during extended shutdown periods, the use of overtime should be considered on an individual basis and not for the entire staff on a shift.

Any deviation from the above guidelines shall be authorized by the AGM-PO, Assistant General Manager-Plant Support (AGM-PS), or by higher levels of management, in accordance with established procedures and with documentation of the basis for granting the deviation.

Controls shall be included in the procedures such that individual overtime shall be reviewed monthly by the AGM-PO, AGM-PS, or designee to ensure that excessive hours have not been assigned. Routine deviation from the above guidelines is not authorized.

f. The Operations Manager shall hold an active or inactive SRO license.

g. The Shift Technical Advisor (STA) shall provide advisory technical support to the Shift Supervisor (SS) in the areas of thermal hydraulics, reactor engineering, and plant analysis with regard to the safe operation of the unit. In addition, the STA shall meet the qualifications specified by the Commission Policy Statement on Engineering Expertise on Shift.

5.6 Reporting Requirements (continued)

5.6.5 CORE OPERATING LIMITS REPORT (COLR)

a. Core operating limits shall be established prior to each reload cycle, or prior to any remaining portion of a reload cycle, and shall be documented in the COLR for the following:

1) Control Rod Block Instrumentation - Rod Block Monitor for Specification 3.3.2.1.

2) The Average Planar Linear Heat Generation Rate for Specification 3.2.1.

3) The Minimum Critical Power Ratio for Specifications 3.2.2 and 3.3.2.1.

b. The analytical methods used to determine the core operating limits shall be those previously reviewed and approved by the NRC, specifically those described in the following documents:

1) NEDE-24011-P-A, "General Electric Standard Application for Reactor Fuel," (applicable amendment specified in the COLR).

2) "Safety Evaluation by the Office of Nuclear Reactor Regulation Supporting Amendment Nos. 151 and 89 to Facility Operating Licenses DPR-57 and NPF-5," dated January 22, 1988.

c. The core operating limits shall be determined such that all specified acceptable fuel design limits will be met.

d. The COLR, including any mid-cycle revisions or supplements, shall be provided upon issuance for each reload cycle to the NRC.

5.6.6 Reactor Coolant System (RCS) PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR)

a. RCS pressure and temperature limits for heatup, cooldown, low temperature operation, criticality, and hydrostatic testing as well as heatup and cooldown rates shall be

(continued)

5.6 Reporting Requirements

5.6.6 Reactor Coolant System (RCS) PRESSURE AND TEMPERATURE LIMITS REPORT (PTLR)

a. (continued)

established and documented in the PTLR for LCO 3.4.9, "RCS Pressure and Temperature (P/T) Limits."

b. The analytical methods used to determine the RCS pressure and temperature limits shall be determined in accordance with Regulatory Guide 1.99.

c. The PTLR shall be provided to the NRC upon issuance for each reactor vessel fluency period and for any revision or supplement thereto.

5.6.7 Post Accident Monitoring (PAM) Instrumentation Report

When a report is required by LCO 3.3.3.1, "Post Accident Monitoring (PAM) Instrumentation," a report shall be submitted within the following 14 days. The report shall outline the preplanned alternate method of monitoring, the cause of the inoperability, and the plans and schedule for restoring the instrumentation channels of the Function to OPERABLE status.

UNIT 2 IMPROVED BASES

BASES

LCO

12. RHR Service Water Flow (continued)

primary indication used by the operator during an accident. Therefore, the PAM specification deals specifically with this portion of the instrument channel.

APPLICABILITY

The PAM instrumentation LCO is applicable in MODES 1 and 2. These variables are related to the diagnosis and preplanned actions required to mitigate DBAs. The applicable DBAs are assumed to occur in MODES 1 and 2. In MODES 3, 4, and 5, plant conditions are such that the likelihood of an event that would require PAM instrumentation is extremely low; therefore, PAM instrumentation is not required to be OPERABLE in these MODES.

ACTIONS

Note 1 has been added to the ACTIONS to exclude the MODE change restriction of LCO 3.0.4. This exception allows entry into the applicable MODE while relying on the ACTIONS even though the ACTIONS may eventually require plant shutdown. This exception is acceptable due to the passive function of the instruments, the operator's ability to diagnose an accident using alternative instruments and methods, and the low probability of an event requiring these instruments.

Note 2 has been provided to modify the ACTIONS related to PAM instrumentation channels. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable PAM instrumentation channels provide appropriate compensatory measures for separate Functions. As such, a Note has been provided that allows separate Condition entry for each inoperable PAM Function.

(continued)

BASES

ACTIONS (continued)

A.1

When one or more Functions have one required channel that is inoperable, the required inoperable channel must be restored to OPERABLE status within 30 days. The 30 day Completion Time is based on operating experience and takes into account the remaining OPERABLE channels (or, in the case of a Function that has only one required channel, other non-Regulatory Guide 1.97 instrument channels to monitor the Function), the passive nature of the instrument (no critical automatic action is assumed to occur from these instruments), and the low probability of an event requiring PAM instrumentation during this interval.

B.1

If a channel has not been restored to OPERABLE status in 30 days, this Required Action specifies initiation of action in accordance with Specification 5.6.7, which requires a written report to be submitted to the NRC. This report discusses the results of the root cause evaluation of the inoperability and identifies proposed restorative actions. This action is appropriate in lieu of a shutdown requirement, since alternative actions are identified before loss of functional capability, and given the likelihood of plant conditions that would require information provided by this instrumentation.

C.1

When one or more Functions have two or more required channels that are inoperable (i.e., two channels inoperable in the same Function), all but one channel in the Function should be restored to OPERABLE status within 7 days. The Completion Time of 7 days is based on the relatively low probability of an event requiring PAM instrument operation and the availability of alternate means to obtain the required information. Continuous operation with two required channels inoperable in a Function is not acceptable because the alternate indications may not fully meet all performance qualification requirements applied to the PAM instrumentation. Therefore, requiring restoration of one inoperable channel of the Function limits the risk that the

(continued)

B 3.3 INSTRUMENTATION

B 3.3.8.1 Loss of Power (LOP) Instrumentation

BASES

BACKGROUND

Successful operation of the required safety functions of the Emergency Core Cooling Systems (ECCS) is dependent upon the availability of adequate power sources for energizing the various components such as pump motors, motor operated valves, and the associated control components. The LOP instrumentation monitors the 4.16 kV emergency buses. Offsite power is the preferred source of power for the 4.16 kV emergency buses. If the monitors determine that insufficient power is available, the buses are disconnected from the offsite power sources and connected to the onsite diesel generator (DG) power sources.

Each 4.16 kV emergency bus has its own independent LOP instrumentation and associated trip logic. The voltage for each bus is monitored at two levels: 4.16 kV Emergency Bus Undervoltage Loss of Voltage and Degraded Voltage, however, only the Loss of Voltage Function is part of this LCO. The Loss of Voltage Function causes various bus transfers and disconnects and is monitored by two undervoltage relays for each emergency bus, whose outputs are arranged in a two-out-of-two logic configuration for all affected components except the DGs. The DG start logic configuration is one-out-of-two (Ref. 1). The channels include electronic equipment (e.g., trip units) that compares measured input signals with pre-established setpoints. When the setpoint is exceeded, the channel output relay actuates, which then outputs a LOP trip signal to the trip logic.

Each 4.16 kV emergency bus has its own independent LOP alarm instrumentation to provide an anticipatory alarm and the initiation of corrective measures to restore emergency bus voltages. The alarms are set higher than the LOP trip relays. The alarm setpoints are approximately midway between the calculated minimum expected voltage and the calculated minimum required voltage, based on the maximum expected operating; i.e., non-LOCA, load conditions. The alarm setpoints signify that adequate voltage is available for normal operations. The LOP anticipatory alarms provide a total time delay of 60 seconds to reduce the possibility

(continued)

BASES

BACKGROUND (continued)

of nuisance alarms, while permitting prompt detection of potential low voltage conditions.

Each 4.16 kV emergency bus has a dedicated low voltage annunciator fed by two relays and their associated time delays. The logic for the annunciation function is arranged in a one-out-of-two configuration.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The LOP instrumentation is required for Engineered Safety Features to function in any accident with a loss of offsite power. The required channels of LOP instrumentation ensure that the ECCS and other assumed systems powered from the DGs, provide plant protection in the event of any of the Reference 2, 3, and 4 analyzed accidents in which a loss of offsite power is assumed. The initiation of the DGs on loss of offsite power, and subsequent initiation of the ECCS, ensure that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Accident analyses credit the loading of the DG based on the concurrent loss of offsite power during a loss of coolant accident. The diesel starting and loading times have been included in the delay time associated with each safety system component requiring DG supplied power following a loss of offsite power.

The LOP alarm instrumentation is required to initiate manual actions to restore the 4.16 kV emergency bus voltages or to initiate a plant shutdown. The required channels of LOP alarm instrumentation ensure the initiation of manual actions to protect the ECCS and other assumed systems from degraded voltage without initiating an unnecessary automatic disconnect from the preferred offsite power source. The occurrence of an undervoltage degraded voltage condition credits the manual actions to mitigate the condition and ensure plant safety is maintained.

The LOP instrumentation satisfies Criterion 3 of the NRC Policy Statement (Ref. 5), except that credit is taken for manual actions.

The OPERABILITY of the LOP instrumentation is dependent upon the OPERABILITY of the individual instrumentation channel Functions specified in Table 3.3.8.1-1. Each Function must have a required number of OPERABLE channels per 4.16 kV emergency bus, with their setpoints within the specified Allowable Values. A channel is inoperable if its actual trip setpoint is not within its required Allowable Value. The setpoint is calibrated consistent with applicable procedures (nominal trip setpoint).

The Allowable Values are specified for the 4.16 kV Emergency Bus Undervoltage Function. Nominal trip setpoints are specified in the setpoint calculations. The nominal setpoints are selected, based on engineering judgment, to ensure that the setpoints do not exceed the Allowable Value between CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within the Allowable Value, is acceptable. Trip setpoints are those predetermined values of output and time delay at which an action should take place. The setpoints

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

are compared to the actual process parameter (e.g., degraded voltage), and when the measured output value of the process parameter exceeds the setpoint and time delay, the associated device (e.g., trip relay) changes state.

The 4.16 kV undervoltage degraded voltage trip setpoints were determined in accordance with the NRC staff positions contained in an NRC letter dated June 2, 1977, except that manual actions are credited for restoring bus voltages or initiating a plant shutdown in the range of 78.8 to 92% of 4.16 kV. The undervoltage degraded voltage setpoint represents a point on the inverse time characteristic curve for the relay. The anticipatory alarm setpoints are approximately midway between the calculated minimum expected voltage and the calculated minimum required voltage, based on maximum expected operating; i.e., non-LOCA, conditions.

The specific Applicable Safety Analyses, LCO, and Applicability discussions are listed below on a Function by Function basis.

1. 4.16 kV Emergency Bus Undervoltage (Loss of Voltage)

Loss of voltage on a 4.16 kV emergency bus indicates that offsite power may be completely lost to the respective emergency bus and is unable to supply sufficient power for proper operation of the applicable equipment. Therefore, the power supply to the bus is transferred from offsite power to DG power when the voltage on the bus drops below the Loss of Voltage Function Allowable Values (loss of voltage with a short time delay). This ensures that adequate power will be available to the required equipment.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The Bus Undervoltage Allowable Values are low enough to prevent inadvertent power supply transfer, but high enough to ensure that power is available to the required equipment. The Time Delay Allowable Values are long enough to provide time for the offsite power supply to recover to normal voltages, but short enough to ensure that power is available to the required equipment.

Two channels of 4.16 kV Emergency Bus Undervoltage (Loss of Voltage) Function per associated emergency bus are only required to be OPERABLE when the associated DG is required to be OPERABLE to ensure that no single instrument failure can preclude the DG function. (Two channels input to each of the three DGs.) Refer to LCO 3.8.1, "AC Sources — Operating," and 3.8.2, "AC Sources — Shutdown," for Applicability Bases for the DGs.

2. 4.16 kV Emergency Bus Undervoltage (Degraded Voltage)

A reduced voltage condition on a 4.16 kV emergency bus indicates that, while offsite power may not be completely lost to the respective emergency bus, available power may be insufficient for starting large ECCS motors without risking damage to the motors that could disable the ECCS function. Therefore, power supply to the bus is transferred from offsite power to onsite DG power when the voltage on the bus drops below the Degraded Voltage Function Allowable Values (degraded voltage with time delay). This ensures that adequate power will be available to the required equipment.

The Bus Undervoltage Allowable Values are low enough to prevent inadvertent power supply transfer, but high enough to ensure that sufficient power is available to the large ECCS motors. The Time Delay Allowable Values are long enough for the offsite power supply to usually recover. This minimizes the potential that short duration disturbances will adversely impact the availability of the offsite power supply. Manual actions are credited in the range of 78.8 to 92% of 4.16 kV to restore bus voltages or to initiate a plant shutdown. The range specified for manual actions indicates that sufficient power is available to the large ECCS motors; however, sufficient voltage for equipment at lower voltages required for LOCA conditions may not be available.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Two channels of 4.16 kV Emergency Bus Undervoltage (Degraded Voltage) Function per associated bus are only required to be OPERABLE when the associated DG is required to be OPERABLE to ensure that no single instrument failure can preclude the DG function. (Two channels input to each of the three emergency buses and DGs.) Refer to LCO 3.8.1 and LCO 3.8.2 for Applicability Bases for the DGs.

3. 4.16 kV Emergency Bus Undervoltage (Anticipatory Alarm)

A reduced voltage condition on a 4.16 kV emergency bus indicates that, while offsite power is adequate for normal operating conditions, available power may be marginal for some equipment required for LOCA conditions. Therefore, the anticipatory alarms actuate when the 4.16 kV bus voltages approach the minimum required voltage for normal; i.e., non-LOCA, conditions. This ensures that manual actions will be initiated to restore the bus voltages or to initiate a plant shutdown.

One channel of the 4.16 kV emergency bus undervoltage (Anticipatory Alarm) function per the associated bus is only required to be OPERABLE when the associated DG is required to be OPERABLE. (Two channels input to each of the three emergency buses.)

ACTIONS

A Note has been provided to modify the ACTIONS related to LOP instrumentation channels. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition, discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable LOP instrumentation channels provide appropriate compensatory measures for separate inoperable channels. As such, a Note has been provided that allows separate Condition entry for each inoperable LOP instrumentation channel.

(continued)

BASES

ACTIONS

A.1

With one or more channels of Function 1 or 2 inoperable, the Function is not capable of performing the intended function. Therefore, only 1 hour is allowed to restore the inoperable channel to OPERABLE status. The Required Action does not allow placing a channel in trip since this action will result in a DG initiation. I

(continued)

BASES

ACTIONS

A.1 (continued)

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. The 1 hour Completion Time is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

B.1

Each 4.16 kV bus has a dedicated annunciator fed by two relays and their associated time delays in a one-out-of-two logic configuration. Only one relay and its associated time delay is required to be OPERABLE. Therefore, the loss of the required relay or time delay renders Function 3 incapable of performing the intended function. Since the intended function is to alert personnel to a lowering voltage condition and the voltage reading is available for each bus on the control room front panels, the Required Action is verification of the voltage to be above the annunciator setpoint (nominal) hourly.

C.1

If any Required Action and associated Completion Time are not met, the associated Function is not capable of performing the intended function. Therefore, the associated DG(s) is declared inoperable immediately. This requires entry into applicable Conditions and Required Actions of LCO 3.8.1 and LCO 3.8.2, which provide appropriate actions for the inoperable DG(s).

SURVEILLANCE REQUIREMENTS

As noted at the beginning of the SRs, the SRs for each LOP instrumentation Function are located in the SRs column of Table 3.3.8.1-1. The Surveillances are modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the associated Function maintains DG initiation capability (for Functions 1 and 2) and annunciation capability (for Function 3). Functions 1

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

and 2 maintain DG initiation capability provided two DGs can be initiated by the Function. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken.

SR 3.3.8.1.1

Performance of the CHANNEL CHECK once every 12 hours ensures that a gross failure of instrumentation or a failure of annunciation has not occurred. A CHANNEL CHECK is defined for Function 3 to be a comparison of the annunciator status to the bus voltage and an annunciator test confirming the annunciator is capable of lighting and sounding. A CHANNEL CHECK will detect gross channel failure or an annunciator failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

If a channel is outside the match criteria, it may be an indication that the instrument has drifted outside its limit.

The frequency is based upon operating experience that demonstrates channel failure is rare. Thus, performance of the CHANNEL CHECK ensures that undetected outright channel or annunciator failure is limited to 12 hours. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with channels required by the LCO.

SR 3.3.8.1.2

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

The Frequency of 31 days is based on operating experience with regard to channel OPERABILITY and drift, which demonstrates that failure of more than one channel of a given Function in any 31 day interval is a rare event.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.8.1.3

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations, consistent with the plant specific setpoint methodology.

The Frequency is based upon the assumption of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.8.1.4

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required actuation logic for a specific channel. The system functional testing performed in LCO 3.8.1 and LCO 3.8.2 overlaps this Surveillance to provide complete testing of the assumed safety functions.

The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at the 18 month Frequency.

REFERENCES

1. FSAR, Section 8.3.1.
2. FSAR, Section 5.2.
3. FSAR, Section 6.3.
4. FSAR, Chapter 15.
5. NRC No. 93-102, "Final Policy Statement on Technical Specification Improvements," July 23, 1993.

B 3.3 INSTRUMENTATION

B 3.3.8.2 Reactor Protection System (RPS) Electric Power Monitoring

BASES

BACKGROUND

RPS Electric Power Monitoring System is provided to isolate the RPS bus from the motor generator (MG) set or an alternate power supply in the event of overvoltage, undervoltage, or underfrequency. This system protects the loads connected to the RPS bus against unacceptable voltage and frequency conditions (Ref. 1) and forms an important part of the primary success path of the essential safety circuits. Some of the essential equipment powered from the RPS buses includes the RPS logic, scram solenoids, and various valve isolation logic (e.g., residual heat removal shutdown cooling).

RPS electric power monitoring assembly will detect any abnormal high or low voltage or low frequency condition in the outputs of the two MG sets or the alternate power supply and will de-energize its respective RPS bus, thereby causing all safety functions normally powered by this bus to de-energize.

In the event of failure of an RPS Electric Power Monitoring System (e.g., both inseries electric power monitoring assemblies), the RPS loads may experience significant effects from the unregulated power supply. Deviation from the nominal conditions can potentially cause damage to the scram solenoids and other Class 1E devices.

In the event of a low voltage condition for an extended period of time, the scram solenoids can chatter and potentially lose their pneumatic control capability, resulting in a loss of primary scram action.

In the event of an overvoltage condition, the RPS logic relays and scram solenoids, as well as the main steam isolation valve (MSIV) solenoids, may experience a voltage higher than their design voltage. If the overvoltage condition persists for an extended time period, it may cause equipment degradation and the loss of plant safety function.

Two redundant Class 1E circuit breakers are connected in series between each RPS bus and its MG set, and between each RPS bus and its alternate power supply. Each of these

(continued)

BASES

BACKGROUND (continued)

b. 3100 kW — 2000 hours,

c. 3250 kW — 300 hours, and

d. 3500 kW — 30 minutes.

DG 1B has the following ratings:

a. 2850 kW — 1000 hours, and

b. 3250 kW — 168 hours.

A description of the Unit 1 onsite power sources is provided in the Bases for Unit 1 LCO 3.8.1.

APPLICABLE SAFETY ANALYSES

The initial conditions of DBA and transient analyses in the FSAR, Chapter 6 (Ref. 4) and Chapter 15 (Ref. 5), assume ESF systems are OPERABLE. The AC electrical power sources are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System (RCS), and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.5, Emergency Core Cooling System (ECCS) and Reactor Core Isolation Cooling (RCIC) System; and Section 3.6, Containment Systems.

The OPERABILITY of the AC electrical power sources is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This includes maintaining the onsite or offsite AC sources OPERABLE during accident conditions in the event of:

a. An assumed loss of all offsite power sources or all onsite AC power sources; and

b. A postulated worst case single failure.

AC sources satisfy Criterion 3 of the NRC Policy Statement (Ref. 13).

(continued)

BASES (continued)

LCO

Two qualified circuits between the offsite transmission network and the onsite Unit 2 Class 1E Distribution System and three separate and independent DGs (2A, 2C, and 1B) ensure availability of the required power to shut down the reactor and maintain it in a safe shutdown condition after an anticipated operational occurrence (AOO) or a postulated DBA. In addition, since some components required by Unit 2 are powered from Unit 1 sources (i.e., Standby Gas Treatment (SGT) System, Main Control Room Environmental Control (MCREC) System, and Control Room Air Conditioning (AC) System), one qualified circuit between the offsite transmission network and the onsite Unit 1 Class 1E Distribution System and one Unit 1 DG (1A or 1C) must also be OPERABLE.

Qualified offsite circuits are those that are described in the FSAR, and are part of the licensing basis for the unit. Each offsite circuit must be capable of maintaining rated frequency and voltage, and accepting required loads during an accident, while connected to the ESF buses. For the purpose of this LCO, each Unit 2 offsite circuit consists of incoming breaker and disconnect to the respective 2C and 2D SATs, the 2C and 2D transformers, and the respective circuit path including feeder breakers to 4.16 kV ESF buses. (However, for design purposes, the offsite circuit excludes the feeder breakers to each 4.16 kV ESF bus). Feeder breakers from each circuit to the 2F ESF bus are required to be OPERABLE; however, only one feeder breaker per bus to the 2E and 2G ESF buses is required to be OPERABLE, but they must be from different SATs (e.g., 2E feeder breaker from the 2C SAT and the 2G feeder breaker from the 2D SAT). With 2E and 2G ESF buses both fed from one SAT (normal line up is both buses fed from 2D SAT), both feeder breakers to each of these ESF buses are required to be OPERABLE. The Unit 1 offsite circuit also consists of the incoming breaker and disconnect to the 4.16 kV ESF buses required to be OPERABLE to provide power to the Unit 1 equipment required by LCO 3.6.4.7, LCO 3.7.4, and LCO 3.7.5.

Each DG must be capable of starting, accelerating to rated frequency and voltage, and connecting to its respective ESF bus on detection of bus undervoltage. This sequence must be accomplished within 12 seconds. Each DG must also be capable of accepting required loads within the assumed loading sequence intervals, and must continue to operate until offsite power can be restored to the ESF buses. These

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.2 (continued)

Note 6 modifies the Surveillance by stating that starting transients above the upper voltage limit do not invalidate this test.

Notes 7 modifies this Surveillance by stating that momentary load transients because of changing bus loads do not invalidate this test.

Note 8 indicates that this Surveillance is required to be conducted on only one DG at a time in order to avoid common cause failures that might result from offsite circuit or grid perturbations.

The normal 31 day Frequency for SR 3.8.1.2 is consistent with Regulatory Guide 1.108 (Ref. 9). This Frequency provides adequate assurance of DG OPERABILITY, while minimizing degradation resulting from testing.

SR 3.8.1.3

This SR provides verification that the level of fuel oil in the day tank is at or above the level at which fuel oil is automatically added. The level is expressed as an equivalent volume in gallons, and is selected to ensure adequate fuel oil for a minimum of 1 hour of DG operation at full load plus 10%. The actual amount required to meet the SR (900 gallons) will provide approximately 3.5 hours of DG operation at full load.

The 31 day Frequency is adequate to ensure that a sufficient supply of fuel oil is available, since low level alarms are provided and operators would be aware of any large uses of fuel oil during this period.

SR 3.8.1.4

Microbiological fouling is a major cause of fuel oil degradation. There are numerous bacteria that can grow in fuel oil and cause fouling, but all must have a water environment in order to survive. Removal of water from the fuel oil day tanks once every 184 days eliminates the necessary environment for bacterial survival.

SURVEILLANCE REQUIREMENTS

SR 3.8.1.4 (continued)

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.4 (continued)

in the fuel oil during DG operation. Water in the day tank may come from condensation, rain water, contaminated fuel oil, and breakdown of the fuel oil by bacteria. Checking for and removal of accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. The Surveillance Frequency is based on engineering judgment and has shown to be acceptable through operating experience. This SR is for preventive maintenance. The presence of water does not necessarily represent a failure of this SR provided that accumulated water is removed during performance of this Surveillance.

SR 3.8.1.5

This SR helps to ensure the availability of the standby electrical power supply to mitigate DBAs and transients and maintain the unit in a safe shutdown condition. This Surveillance verifies that the DGs are capable of a "fast cold" start, synchronizing, and accepting a load more closely simulating accident loads. A minimum run time of 60 minutes is required to stabilize engine temperatures, while minimizing the time that the DG is connected to the offsite source.

SR 3.8.1.5 requires that, at a 184 day Frequency, the DG starts from standby conditions and achieves required voltage and frequency within 12 seconds. The 12 second start requirement supports the assumptions in the design basis LOCA analysis of FSAR, Chapter 6 (Ref. 4).

For the purposes of this testing, the DGs are started from standby conditions. Standby conditions for a DG mean that the diesel engine coolant and oil are being continuously circulated and temperature is being maintained consistent with manufacturer recommendations.

Although no power factor requirements are established by this SR, the DG is normally operated at a power factor between 0.8 lagging and 1.0. The 0.8 value is the design rating of the machine, while 1.0 is an operational limitation.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.17 (continued)

electrical distribution system, and challenge safety systems. Credit may be taken for unplanned events that satisfy this SR. This Surveillance tests the applicable logic associated with the Unit 2 swing bus. The comparable test specified in the Unit 1 Technical Specifications tests the applicable logic associated with the Unit 1 swing bus. Consequently, a test must be performed within the specified Frequency for each unit. The Note specifying the restriction for not performing the test while the unit is in MODE 1, 2, or 3 does not have applicability to Unit 1. As the Surveillance represents separate tests, the Unit 2 Surveillance should not be performed with Unit 2 in MODE 1, 2, or 3 and the Unit 1 test should not be performed with Unit 1 in MODE 1, 2, or 3.

SR 3.8.1.18

This Surveillance demonstrates that the DG starting independence has not been compromised. Also, this Surveillance demonstrates that each engine can achieve proper speed within the specified time when the DGs are started simultaneously. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil continuously circulated and temperature maintained consistent with manufacturer recommendations. It is permissible to place all three DGs in test simultaneously, for the performance of this Surveillance.

The 10 year Frequency is consistent with the recommendations of Regulatory Guide 1.108 (Ref. 9). This SR is modified by a Note. The reason for the Note is to minimize wear on the DG during testing.

SR 3.8.1.19

With the exception of this Surveillance, all other Surveillances of this Specification (SR 3.8.1.1 through SR 3.8.1.18) are applied only to the Unit 2 DG and offsite circuits, and swing DG. This Surveillance is provided to direct that the appropriate Surveillances for the required Unit 1 DG and offsite circuit are governed by the Unit 1

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.19

Technical Specifications. Performance of the applicable Unit 1 Surveillances will satisfy both any Unit 1 requirements, as well as satisfying this Unit 2 Surveillance requirement. Two exceptions are noted to the Unit 1 SRs of LCO 3.8.1. SR 3.8.1.6 is excepted since only one Unit 1 circuit is required by the Unit 2 Specification. Therefore, there is not necessarily a second circuit to transfer to. SR 3.8.1.18 is excepted since there is only one Unit 1 DG required by the Unit 2 Specification. Therefore, there are not necessarily multiple DGs for simultaneous start.

The Frequency required by the applicable Unit 1 SR also governs performance of that SR for both Units.

(continued)

BASES

REFERENCES

1. 10 CFR 50, Appendix A, GDC 17.
2. FSAR, Sections 8.2 and 8.3.
3. Regulatory Guide 1.9, March 1971.
4. FSAR, Chapter 6.
5. FSAR, Chapter 15.
6. Regulatory Guide 1.93, December 1974.
7. Generic Letter 84-15.
8. 10 CFR 50, Appendix A, GDC 18.
9. Regulatory Guide 1.108, August 1977.
10. Regulatory Guide 1.137, October 1979.
11. IEEE Standard 387 - 1984.
12. IEEE Standard 308 - 1980.
13. NRC No. 93-102, "Final Policy Statement on Technical Specification Improvements," July 23, 1993.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.2 AC Sources — Shutdown

BASES

BACKGROUND

A description of the AC sources is provided in the Bases for LCO 3.8.1, "AC Sources — Operating."

APPLICABLE SAFETY ANALYSES

The OPERABILITY of the minimum AC sources during MODES 4 and 5 and during movement of irradiated fuel assemblies in the Unit 1 secondary containment ensures that:

a. The facility can be maintained in the shutdown or refueling condition for extended periods;

b. Sufficient instrumentation and control capability is available for monitoring and maintaining the unit status; and

c. Adequate AC electrical power is provided to mitigate events postulated during shutdown, such as an inadvertent draindown of the vessel or a fuel handling accident.

In general, when the unit is shut down the Technical Specifications requirements ensure that the unit has the capability to mitigate the consequences of postulated accidents. However, assuming a single failure and concurrent loss of all offsite or loss of all onsite power is not required. The rationale for this is based on the fact that many Design Basis Accidents (DBAs) that are analyzed in MODES 1, 2, and 3 have no specific analyses in MODES 4 and 5. Postulated worst case bounding events are deemed not credible in MODES 4 and 5 because the energy contained within the reactor pressure boundary, reactor coolant temperature and pressure, and corresponding stresses result in the probabilities of occurrences significantly reduced or eliminated, and minimal consequences. These deviations from DBA analysis assumptions and design requirements during shutdown conditions are allowed by the LCO for required systems.

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BASES

SURVEILLANCE REQUIREMENTS

Table 3.8.6-1 (continued)

electron transfer capability. The Category C limit for voltage is based on IEEE-450 (Ref. 3), which states that a cell voltage of 2.07 V or below, under float conditions and not caused by elevated temperature of the cell, indicates internal cell problems and may require cell replacement. The Category C limit for float charging current is characteristic of a battery that is approaching a fully charged condition. The limit for each battery is specified in Reference 4.

REFERENCES

1. FSAR, Chapter 6.

2. FSAR, Chapter 15.

3. IEEE Standard 450 - 1987.

4. Technical Requirements Manual.

5. NRC No. 93-102, "Final Policy Statement on Technical Specification Improvements," July 23, 1993.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.7 Distribution Systems — Operating

BASES

BACKGROUND

The onsite Class 1E AC and DC electrical power distribution system is divided into redundant and independent AC and DC electrical power distribution subsystems.

The primary AC distribution system consists of three 4.16 kV Engineered Safety Feature (ESF) buses each having an offsite source of power as well as a dedicated onsite diesel generator (DG) source. Each 4.16 kV ESF bus is normally connected to a normal source startup auxiliary transformer (SAT) (2D). During a loss of the normal offsite power source to the 4.16 kV ESF buses, the alternate supply breaker from SAT 2C attempts to close. If all offsite sources are unavailable, the onsite emergency DGs supply power to the 4.16 kV ESF buses.

The secondary plant distribution system includes 600 VAC emergency buses 2C and 2D and associated load centers, and transformers.

There are two independent 125/250 VDC station service electrical power distribution subsystems and three independent 125 VDC DG electrical power distribution subsystems that support the necessary power for ESF functions.

A description of the Unit 1 AC and DC electrical power distribution system is provided in the Bases for Unit 1 LCO 3.8.7, "Distribution System—Operating."

The list of required Unit 2 distribution buses is presented in LCO 3.8.7.

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the FSAR, Chapter 6 (Ref. 1) and Chapter 15 (Ref. 2), assume ESF systems are OPERABLE. The AC and DC electrical power distribution systems are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to

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BASES

APPLICABLE SAFETY ANALYSES (continued)

ESF systems so that the fuel, Reactor Coolant System, and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.5, Emergency Core Cooling Systems (ECCS) and Reactor Core Isolation Cooling (RCIC) System; and Section 3.6 Containment Systems.

The OPERABILITY of the AC and DC electrical power distribution subsystems is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This includes maintaining distribution systems OPERABLE during accident conditions in the event of:

a. An assumed loss of all offsite power sources or all onsite AC electrical power sources; and

b. A postulated worst case single failure.

The AC and DC electrical power distribution system satisfies Criterion 3 of the NRC Policy Statement (Ref. 4).

LCO

The Unit 2 AC and DC electrical power distribution subsystems are required to be OPERABLE. The required Unit 2 electrical power distribution subsystems listed in LCO 3.8.7 ensure the availability of AC and DC electrical power for the systems required to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence (AOO) or a postulated DBA.

Should one or more buses not listed in LCO 3.8.7 become inoperable due to a failure not affecting the OPERABILITY of a bus listed in LCO 3.8.7 (e.g., a breaker supplying a single MCC faults open), the individual loads on the bus would be considered inoperable, and the appropriate Conditions and Required

(continued)

BASES

LCO (continued)

Actions of the LCOs governing the individual loads would be entered. If however, one or more of these buses is inoperable due to a failure also affecting the OPERABILITY of a bus listed in LCO 3.8.7 (e.g., loss of a 4.16 kV ESF bus, which results in de-energization of all buses powered from the 4.16 kV ESF bus), the Conditions and Required Actions of the LCO for the individual loads are not required to be entered, since LCO 3.0.6 allows this exception (i.e., the loads are inoperable due to the inoperability of a support system governed by a Technical Specification; the 4.16 kV ESF bus). In addition, since some components required by Unit 2 receive power through Unit 1 electrical power distribution subsystems (e.g., Standby Gas Treatment (SGT) System, Main Control Room Environmental Control (MCREC) System, and Control Room Air Conditioning (AC) System), the Unit 1 AC and DC electrical power distribution subsystems needed to support the required equipment must also be OPERABLE.

Maintaining the Division 1 and 2 and swing bus AC and DC electrical power distribution subsystems OPERABLE ensures that the redundancy incorporated into the design of ESF is not defeated. Therefore, a single failure within any system or within the electrical power distribution subsystems will not prevent safe shutdown of the reactor.

The AC electrical power distribution subsystem requires the associated buses and electrical circuits to be energized to their proper voltages. OPERABLE DC electrical power distribution subsystems require the associated buses to be energized to their proper voltage from either the associated battery or charger.

In addition, tie breakers between redundant safety related AC and DC power distribution subsystems, if they exist, must be open. This prevents any electrical malfunction in any power distribution subsystem from propagating to the redundant subsystem, which could cause the failure of a redundant subsystem and a loss of essential safety function(s). If any tie breakers are closed, the electrical power distribution subsystem which is not being powered from its normal source (i.e., it is being powered from its redundant electrical power distribution subsystem) is considered inoperable. This applies to the onsite, safety related, redundant electrical power distribution subsystems.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.8.7.1

This Surveillance verifies that the AC and DC electrical power distribution systems are functioning properly, with the correct circuit breaker alignment. The correct breaker alignment ensures the appropriate separation and independence of the electrical buses are maintained, and the appropriate voltage is available to each required bus. The verification of proper voltage availability on the buses ensures that the required voltage is readily available for motive as well as control functions for critical system loads connected to these buses. The 7 day Frequency takes into account the redundant capability of the AC and DC electrical power distribution subsystems, and other indications available in the control room that alert the operator to subsystem malfunctions.

REFERENCES

1. FSAR, Chapter 6.

2. FSAR, Chapter 15.

3. Regulatory Guide 1.93, December 1974.

4. NRC No. 93-102, "Final Policy Statement on Technical Specification Improvements," July 23, 1993.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.8 Distribution Systems — Shutdown

BASES

BACKGROUND

A description of the AC and DC electrical power distribution system is provided in the Bases for LCO 3.8.7, "Distribution Systems — Operating."

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident and transient analyses in the FSAR, Chapter 6 (Ref. 1) and Chapter 15 (Ref. 2), assume Engineered Safety Feature (ESF) systems are OPERABLE. The AC and DC electrical power distribution systems are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System, and containment design limits are not exceeded.

The OPERABILITY of the AC and DC electrical power distribution system is consistent with the initial assumptions of the accident analyses and the requirements for the supported systems' OPERABILITY.

The OPERABILITY of the minimum AC and DC electrical power sources and associated power distribution subsystems during MODES 4 and 5 and during movement of irradiated fuel assemblies in the unit 1 secondary containment ensures that:

a. The facility can be maintained in the shutdown or refueling condition for extended periods;

b. Sufficient instrumentation and control capability is available for monitoring and maintaining the unit status; and

c. Adequate power is provided to mitigate events postulated during shutdown, such as an inadvertent draindown of the vessel or a fuel handling accident.

The AC and DC electrical power distribution systems satisfy Criterion 3 of the NRC Policy Statement (Ref. 3).

(continued)

UNIT 2 MARKUP OF CURRENT TECHNICAL SPECIFICATIONS AND DISCUSSION OF CHANGES

INSTRUMENTATION

3/4.3.8 DEGRADED STATION VOLTAGE PROTECTION INSTRUMENTATION

LIMITING CONDITION FOR OPERATION

LCO 3.3.8.1

3.3.8 The degraded station voltage relay channels shown in Table 3.3.8-1 shall be OPERABLE.

APPLICABILITY: CONDITIONS 1, 2, and 3. — proposed 2nd Applicability — M.1

ACTION:

M.4 — ACTION A

a. With the number of OPERABLE channels one less than the required OPERABLE channels, operation may proceed until performance of the next scheduled instrument functional test provided a trip signal is placed in the LOSP lock-out relay logic for the applicable inoperable channel. — A.1 — M.2 — within 1 hour

proposed ACTION B

proposed ACTION C

b. One instrument channel may be inoperable for up to 6 hours to perform required surveillances prior to entering other applicable ACTIONS. — M.2 — L.1

proposed Note to Surveillance Requirements

SURVEILLANCE REQUIREMENTS

4.3.8 Each of the above required degraded station voltage relay channels shall be demonstrated OPERABLE by performance of the CHANNEL CALIBRATION and CHANNEL FUNCTIONAL TEST operation at the frequencies shown in Table 4.3.8-1. — SR 3.3.8.1.3

SR 3.3.8.1.2

TABLE ~~3.3.8-1~~ 3.3.8.1-1 (C)

LOP

~~DEGRADED~~ STATION VOLTAGE PROTECTION INSTRUMENTATION

Ref. No. (a)	Instrument	Required Operable Channels	Channels Required To Trip (L.A.1)	~~Trip Setting~~ Acceptable Value (L.A.1)
1	4.16 kv Emergency Bus Undervoltage Relay (Loss of Voltage Condition)	2/Bus	2/Bus	greater than or equal to 2800 volts At 2800 volts time delay will be less than or equal to 6.5 sec.
2	4.16 kv Emergency Bus Undervoltage Relay (Degraded Voltage Condition)	2/Bus	2/Bus	greater than or equal to 3280 volts At 3280 volts time delay will be less than or equal to 21.5 sec.

(proposed LOP Function 3) (M.4) (C)

~~NOTES FOR TABLE 3.3.8-1~~

~~a. The column entitled "Ref. No." is only for convenience so that a one-to-one relationship can be established between items in Table 3.3.8-1 and items in Table 4.3.8-1.~~

Specification 3.3.8.1

~~TABLE 4.3.8-1~~

~~DEGRADED STATION VOLTAGE PROTECTION INSTRUMENTATION SURVEILLANCE REQUIREMENTS~~

Ref. No. (a)	Instrument (b)	SR 3.3.8.1.1 Instrument Check Minimum Frequency	SR 3.3.8.1.2 Instrument Functional Test Minimum Frequency	SR 3.3.8.1.3 Instrument Calibration Minimum Frequency
1	4.16 kv Emergency Bus Undervoltage Relay (Loss of Voltage Condition)	N/A	Once/month	Once/operating cycle A.2 — 18 months Once/operating cycle
2	4.16 kv Emergency Bus Undervoltage Relay (Degraded Voltage Condition)	N/A	Once/month	Once/operating cycle

M.4 — proposed LOP Function 3

M.3 — proposed SR 3.3.8.1.4

C

C

~~NOTES FOR TABLE 4.3.8-1~~

~~a. The column entitled "Ref. No." is only for convenience so that a one-to-one relationship can be established between items in Table 3.3.8-1 and items in Table 4.3.8-1.~~

b. Surveillance of this instrumentation is required during reactor startup, power operation, and hot shutdown.

Applicability

proposed 2nd Applicability — M.1

Specification 3.3.8.1

3 of 3

DISCUSSION OF CHANGES
ITS: SECTION 3.3.8.1 - LOSS OF POWER INSTRUMENTATION

ADMINISTRATIVE

A.1 The requirement for performing the Instrument Functional Test is included in proposed SR 3.3.8.1.2. It is possible that the test would not be able to be performed with an inoperable channel, and a plant shutdown would be required due to the inability to perform the required surveillance. However, this restriction on continued operation need not be specified as an Action (as is the case in existing Action a); it exists inherently as a result of the Instrument Functional Test requirement. In addition, the channel is not allowed to be placed in trip in the ITS (see comment M.2), thus this statement does not apply. Since no change in operation, requirements or intent is made, the proposed revision to eliminate a specific restriction of continued operation is considered administrative.

A.2 The Frequency of "once/operating cycle" has been changed to "18 months". Since the current operating cycle is not really 18 months, this change is considered administrative.

TECHNICAL CHANGE - MORE RESTRICTIVE

M.1 An additional Applicability has been added, requiring the instruments to be OPERABLE when the associated diesel generators (DGs) are required to be OPERABLE by LCO 3.8.2, AC Sources—Shutdown. This essentially adds a MODE 4 and 5 Applicability when the DGs are required in these MODES. This is consistent with the BWR Standard Technical Specifications, NUREG 1433 and is an additional restriction on plant operation.

M.2 The allowance to place the LOSP lock-out relay in trip has been changed to require restoration of the entire channel. Placing the LOSP lock-out relay in trip does not result in all components affected by the channel receiving a trip signal. In addition, a finite Completion Time of 1 hour has been provided to place an inoperable channel in trip. Currently, no Completion Time is provided. This change is an additional restriction on plant operation.

M.3 An additional Surveillance Requirement has been added (proposed SR 3.3.8.1.4) to perform a LOGIC SYSTEM FUNCTIONAL TEST (LSFT) once per 18 months. This will ensure that the entire logic is functioning properly similar to the current LSFT already required for the ECCS instrumentation (LCO 3.3.5.1), which also provides a DG start signal. This is consistent with the BWR Standard Technical Specifications, NUREG 1433 and is an additional restriction on plant operation.

M.4 To satisfy Criterion 3 of the NRC Policy Statement, Hatch credits manual actions in the range of 78.8 to 92% of 4.16 kV. Entry into this range

TECHNICAL CHANGE - MORE RESTRICTIVE
(continued)

is annunciated. The range specified for manual actions indicates that sufficient power is available to the large ECCS motors; however, sufficient voltage for equipment required for LOCA conditions may not be available at lower voltages. The required channels of LOP annunciation instrumentation ensure the initiation of manual actions to protect the ECCS and other assumed systems from degraded voltage without initiating an unnecessary automatic disconnect from the preferred offsite power source. The LOP anticipatory annunciators provide a total time delay of 60 seconds to reduce the possibility of nuisance annunciators while permitting prompt detection of potential low voltage conditions. Since Hatch takes credit for the annunciators, they have been added to Table 3.3.8.1-1. Additionally, new LCO CONDITION "B" addressing the annunciation Function has been added and the other CONDITIONS renumbered and amended as necessary to account for the annunciation. Appropriate SRs are defined for the annunciator bus undervoltage relays and the associated time delays.

DISCUSSION OF CHANGES
ITS: SECTION 3.3.8.1 - LOSS OF POWER INSTRUMENTATION

TECHNICAL CHANGE - LESS RESTRICTIVE

"Generic"

LA.1 System design and operational details have been relocated to the Bases and procedures. Trip setpoints are an operational detail that is not directly related to the operability of the instrumentation. The Allowable Value is the required limitation for the parameter and this value is retained in Table 3.3.8.1-1. Details relating to system design and operation (e.g., description of action of instrumentation) are also unnecessary in the LCO and have been relocated to the Bases and procedures. The design features and system operation are also described in the FSAR. Changes to the Bases will be controlled by the provisions of the proposed Bases Control Process described in Chapter 5 of the Technical Specifications. Changes to the FSAR and procedures will be controlled by the provisions of 10 CFR 50.59.

"Specific"

L.1 An ACTION has been added (proposed ACTION C) to require declaring the DG inoperable and taking the appropriate actions in the associated DG Specification if a channel is not restored within 1 hour. Currently, the ACTIONS appear to require a Specification 3.0.3 entry, which would result in an immediate shutdown. Since Functions 1 and 2 instrumentation provide a start signal for the DGs (i.e., it supports DG OPERABILITY), the appropriate action would be to declare the DG inoperable. The current requirements are overly restrictive, in that if the diesel were inoperable for other reasons, a 72 hour restoration time is provided; yet currently if an instrument is inoperable but the diesel is otherwise fully OPERABLE, an immediate shutdown is required. The ACTION also applies to Function 3 but would only be entered if both the annunciation and voltage indication were inoperable.

DISCUSSION OF CHANGES
ITS: SECTION 3.3.8.1 - LOSS OF POWER INSTRUMENTATION

TECHNICAL CHANGE - LESS RESTRICTIVE

DISCUSSION OF CHANGES
ITS: SECTION 3.3.8.1 - LOSS OF POWER INSTRUMENTATION

TECHNICAL CHANGE - LESS RESTRICTIVE

TECHNICAL CHANGE - LESS RESTRICTIVE

ELECTRICAL POWER SYSTEMS

SURVEILLANCE REQUIREMENTS

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

SR 3.8.1.1 a. Determined OPERABLE at least once per 7 days by verifying correct breaker alignments and indicated power availability, and

SR 3.8.1.6 b. Demonstrated OPERABLE at least once per 18 months during shutdown by transferring, manually and automatically, unit power supply from the normal circuit to the alternate circuit. (A.5) Note to the SR

4.8.1.1.2 Each diesel generator shall be demonstrated OPERABLE: (L.A.5)

a. In accordance with the frequency specified in Table 4.8.1.1.2-1 on a STAGGERED TEST BASIS (L.6) by: (L.7)

SR 3.8.1.3 1. Verifying the fuel level in the day fuel tanks. Once every 31 days (C)

moved to LCO 3.8.3 (A.10)

2. Verifying the fuel level in the plant fuel storage tank.

3. Verifying the fuel transfer pump can be started and transfers fuel from the storage system to the day tank.

SR 3.8.1.2

4. Verifying that each diesel starts from ambient condition by gradually loading the generator to 1710-2000 kW*, and operating for ≥ 60 minutes, and maintains a steady-state voltage of 4160 ± 420 volts and a steady-state frequency of 60 ± 1.2 Hz.** (M.8)

5. Verifying the diesel generator is aligned to provide standby power to the associated emergency busses. (LA.1)

proposed Notes 1, 3, 5, 6 and 8 to SR 3.8.1.2

(A.4)

proposed Note 2 to SR 3.8.1.2 (L.8)

*Momentary variations outside this band shall not invalidate the test. Note 7 to SR 3.8.1.2

**For the 1B (swing) diesel, a single test will satisfy the requirements for Unit 1 Specification 4.9.A.2.a.1 and Unit 2 Specification 4.8.1.1.2.a.4, with the diesel connected to one unit's emergency bus for one periodic test and connected to the emergency bus in the other unit during the next periodic test. Note 4 to SR 3.8.1.2

Specification 3.8.1

ELECTRICAL POWER SYSTEMS

SURVEILLANCE REQUIREMENTS (Continued)

4.8.1.1.4 Reports - All diesel generator failures, valid or non-valid, shall be reported to the Commission pursuant to 10 CFR 50.73 or Specification 6.9.2, as applicable. If the number of failures in the last 100 valid tests, on a per nuclear unit basis, is ≥ 7, the report shall be supplemented to include the additional information recommended in Regulatory Position C.3.b of Regulatory Guide, 1.108, Revision 1, August 1977.

C

Specification 3.8.1

TABLE 4.8.1.i.2-1

DIESEL GENERATOR TEST SCHEDULE

Number of Failures In Last 20 Valid Tests*	Test Frequency
≤ 1	At least once per 31 days
≥ 2	At least once per 7 days

DELETED

C

*Criteria for determining number of failures and number of valid tests shall be in accordance with Regulatory Position C.2.e of Regulatory Guide 1.108, Revision 1, August 1977, except that only the last 20 tests are used and are determined on a per diesel basis.

TECHNICAL CHANGE - MORE RESTRICTIVE
(continued)

M.5 The DG fuel oil day tanks are proposed to have a Surveillance for the checking for and removal of accumulated water (proposed SR 3.8.1.4). This added restriction provides assurance that water will not degrade the performance of the diesel engine.

M.6 Deleted.

M.7 Deleted.

M.8 The existing tolerance for voltage (± 10%) is being restricted to -10%, +2%. Reducing the allowable overvoltage is based on the acceptable overvoltage limits of equipment on the 600 V buses.

TECHNICAL CHANGE - LESS RESTRICTIVE

"Gen

LA.1 This Surveillance has been deleted in the proposed Technical Specifications. Procedural controls on DG standby alignment, and the definition of OPERABILITY are sufficient to ensure the DG remains aligned to provide standby power. Removal of this Surveillance from the Technical Specifications will have no effect on DG OPERABILITY. Changes to the procedures will be controlled by the provisions of 10 CFR 50.59.

LA.2 This Surveillance has been deleted in the proposed Technical Specifications. Procedural controls on DG inspections recommended by the manufacturer are sufficient to ensure the DG receives the necessary inspections. Removal of this Surveillance from the Technical Specifications will have no effect on DG OPERABILITY. Changes to the procedures will be controlled by the provisions of 10 CFR 50.59.

LA.3 The specific component name of the single largest load need not be detailed within the Technical Specifications. The value of the load, as well as the component itself, are specifically detailed in the Bases, as well as the FSAR. Changes to the Bases will be controlled by the Bases Control Process described in Chapter 5 of the Technical Specifications. Changes to the FSAR are controlled by 10 CFR 50.59. The reference to the single largest load within the Technical Specifications is not necessary to adequately present the requirement. Similarly, the load value for the auto-connected loads is removed from the proposed Technical Specifications.

TECHNICAL CHANGE - LESS RESTRICTIVE
(continued)

LA.3
(continued)

Any change to the loads placed on the DG will be controlled by 10 CFR 50.59 (a design is required to change the loads). Additionally, the voltage range to be maintained during this test is not detailed in the ITS. Any change to the voltage acceptance criteria for the DG will be controlled by 10 CFR 50.59.

LA.4 Any time the OPERABILITY of a system or component has been affected by repair, maintenance, or replacement of a component, post maintenance testing is required to demonstrate OPERABILITY of the system or component. Explicit post maintenance Surveillance Requirements have therefore been deleted from the Specifications. Entry into the applicable modes without performing this post maintenance testing also continues to be allowed as discussed in the Bases for SR 3.0.1.

LA.5 The diesel generator accelerated test frequency requirements are relocated in their current licensing bases form to plant procedures, leaving the Technical Specifications periodic surveillance frequency as 31 days. A plant procedure implements the requirements and responsibilities for tracking emergency DG failures for the determination and reporting of reaching trigger values specified in NUMARC 87-00. These requirements are more restrictive than those specified in NUREG 1433.

"Specific"

L.1 The requested deletion involves the requirement to start the DGs under degraded offsite power conditions. The normal Technical Specification surveillance testing schedule provides adequate assurance that the OPERABLE DGs will be capable of performing their intended safety functions. The inoperability of an offsite AC source in no way affects the reliability of the OPERABLE DGs as previously demonstrated by their normal Technical Specification surveillance testing. In some circumstances, the inoperability of the AC sources will automatically start the associated DG. In these cases, the DG will already be supplying the safety bus. The reliability and availability of the DGs are not adversely affected solely as a result of the loss of offsite circuit(s) and the DG should not be required to be started if this condition exists. Additionally, once the DG started to meet the existing ACTION, the DG manufacturer recommends loading that DG prior to a return to standby status.

The most probable cause of an offsite AC source becoming inoperable is severe weather or an off-normal grid condition. Severe weather or other off-normal grid conditions can also cause the loss of a DG and leave its safety bus without AC power if the DG is tied to the offsite source when it becomes inoperable. NRC Information Notice 84-69 warns against operating DGs tied to offsite power when the unit's AC sources are

TECHNICAL CHANGE - LESS RESTRICTIVE
(continued)

L.9 The limitation on the time to reach full DG load from a manual synchronization is proposed for deletion. DG loading should be done in accordance with manufacturer's recommendations to minimize wear on the engine. Additionally, placing a time limitation on the operator to accomplish this loading results in an increased potential for error and subsequent unavailability of the DG. The starting, loading, subsequent full load operation, and automatic start and loading testing required by other Technical Specification Surveillances is adequate to confirm the DG's capability without the 120-second loading requirement. In addition, for clarity, Note 2 has been added to this SR to specifically allow gradual loading.

L.10 The proposed "hot restart" test (proposed SR 3.8.1.13) does not require the restart be a simulated loss of offsite power (auto-start signal). The "hot restart" is proposed to simply be any start signal, as is required by the monthly test. Furthermore, the specific requirement to be automatically loaded with emergency loads is excessive; the DG has demonstrated its ability to power loads while "hot" (i.e., the 24 hour run). Additionally, the automatic loading is an unnecessary repetition of other SRs which confirm the DG ability to accept sequenced loads. DG loading following the hot restart is proposed to be controlled by plant procedures and appropriate manufacturer recommendations for loading following any DG start. This revision allows greater flexibility in scheduling DG testing while not compromising any necessary demonstration of DG capability.

L.11 Deleted.

L.12 The current Specification 3.0.5 has been moved to LCO 3.8.1, in the form of Required Actions A.2, B.2, C.2, and D.1. These new Required Actions are essentially the same as the current 3.0.5, except for the newly provided Completion Times to perform the checks required by current 3.0.5, item (2), and proposed Required Actions A.2, B.2, C.2 and D.1. This new

ELECTRICAL POWER SYSTEMS

3/4.8.2 ONSITE POWER DISTRIBUTION SYSTEMS

Specification 3.8.7

A.C. DISTRIBUTION - OPERATING

LIMITING CONDITION FOR OPERATION (A.1) <general requirements>

LCO 3.8.7.a (A.1)

3.8.2.1 The following A.C. distribution system buses (A.4), inverters (A.3) moved to LCO 3.5.1 and motor-generator (MG) sets (A.2) shall be OPERABLE with breakers open between redundant buses: (LA.1)

a. 4160 volt Essential Buses 2E, 2F, and 2G,

b. 600 volt Essential Buses 2C and 2D,

c. 120/208 volt Essential Cabinets 2A and 2B,

d. 120/208 volt Instrument Buses 2A and 2B, and

e. A.C. inverters 2R44-S002 and 2R44-S003. (A.3) moved to LCO 3.5.1

(C)

(M.1) proposed LCO 3.8.7.b

APPLICABILITY: CONDITIONS 1, 2 and 3

ACTION: (A.3) moved to LCO 3.5.1

a. With one of the inverters in 3.8.2.1.e inoperable, restore the inverter to an OPERABLE status within a period not to exceed seven (7) consecutive days or be in at least HOT SHUTDOWN within the next 12 hours and be in COLD SHUTDOWN within the following 24 hours.

(M.1) Proposed ACTION A

b. With one of the above required A.C. distribution system buses (A.4) inoperable, restore the inoperable bus to OPERABLE status within 8 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

ACTION C

ACTION E

(M.3) and 16 hours from discovery of failure to meet LCO 3.8.7.a

c. With two or more of the above required A.C. distribution system buses (A.4) or inverters inoperable, restore at least all except one of the inoperable buses and inverters to OPERABLE status within 2 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

(M.2) ACTION F

SURVEILLANCE REQUIREMENTS

4.8.2.1 The above required A.C. distribution system buses and inverters (A.3) shall be determined OPERABLE: moved to LCO 3.5.1

SR 3.8.7.1

a. At least once per 7 days by verifying correct breaker alignment and indicated power availability, and (LA.2)

b. At least once per 31 days by determining that the 250 volt DC/600 volt AC inverters 2R44-S002 and 2R44-S003 are OPERABLE by verifying inverter output voltage of 600 volts ± 5% while supplying their respective buses. (A.3) moved to LCO 3.5.1

Specification 3.8.7

ELECTRICAL POWER SYSTEMS

D.C. DISTRIBUTION - OPERATING

LIMITING CONDITION FOR OPERATION (A.1) <general requirements>

LCO 3.8.7.a (A.1)

3.8.2.3 The following divisions of the D.C. power system shall be OPERABLE:

a. DIVISION I consisting of 125/250 volt D.C. bus No. 2A, the 125/250-volt station battery and at least 2 full capacity chargers.

b. DIVISION II consisting of 125/250-volt D.C. bus No. 2B, the 125/250-volt station battery and at least 2 full capacity chargers.

Proposed LCO 3.8.7.b

APPLICABILITY: CONDITIONS 1, 2 and 3.

See Discussion of Changes for ITS: 3.8.4, DC Sources - Operating, in this section

ACTION:

ACTION D / ACTION E: With one of the above required divisions of the D.C. power system inoperable, restore the inoperable division to OPERABLE status within 2 hours or be in at least HOT SHUTDOWN within the next 12 hours and in COLD SHUTDOWN within the following 24 hours.

and 16 hours from discovery of failure to meet LCO 3.8.7.a

Proposed ACTIONS A & B (M.1)

proposed ACTION F (M.2)

M.3

SURVEILLANCE REQUIREMENTS

SR 3.8.7.1

4.8.2.3.1 Each of the above required divisions of the D.C. power system shall be determined OPERABLE at least once per 7 days by verifying correct breaker alignment and indicated power availability. LA.2

4.8.2.3.2 Each station battery and associated chargers shall be demonstrated OPERABLE:

a. At least once per 7 days by verifying that:

1. The electrolyte level of each pilot cell is between the minimum and maximum level indication marks,

See Discussion of Changes for ITS: 3.8.6, Battery Cell Parameters, in this section

2 of 2

TECHNICAL CHANGE - MORE RESTRICTIVE

M.1
(continued)

now explicitly required for the Unit 1 buses. Therefore, this change, is considered more restrictive on plant operations.

M.2 Current ACTION C of Specification 3.8.2.1 (AC Distribution—Operating) allows two buses to be inoperable for up to 2 hours prior to requiring a shutdown. Current practice is to enter this Action if two buses in different subsystems are inoperable. For example, if 4160 V 2E is deenergized, which results initially in the deenergization of 600 V 2C, 120/208 V essential cabinet 2A and 120/208 V Instrument bus 2A, only ACTION b is entered, and an 8 hour restoration time taken. This is because the cause of the inoperability is the 4160 V bus 2E, a single bus. ACTION C is entered if two or more buses in different subsystems are deenergized. Proposed ACTION F will require an LCO 3.0.3 entry if two or more buses in different subsystems are deenergized. In addition, ACTION F would tie the AC and DC Distribution Systems together, such that, if a loss of assumed safety function occurs, an LCO 3.0.3 entry is required. This ensures a shutdown is immediately commenced if sufficient electrical distribution subsystems to meet accident analysis are not available.

M.3 The proposed Completion Time has a limitation in addition to the 8 hour or 2 hour limit. This additional limit establishes a maximum time allowed for any combination of required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet the LCO. If an AC distribution subsystem is inoperable while, for instance, a DC bus is inoperable and subsequently returned OPERABLE, the LCO may already have been not met for up to 8 hours. This situation could lead to a total duration of 10 hours since initial failure of the LCO to restore the DC distribution system. Then, an AC subsystem could again become inoperable, and the DC distribution restored OPERABLE. This could continue indefinitely. Therefore, to preclude this situation and place an appropriate restriction on any such unusual situation, the additional Completion Time of "16 hours from discovery of failure to meet LCO 3.8.7.a" is proposed.

TECHNICAL CHANGE - LESS RESTRICTIVE

"Generic"

LA.1 The details relating to system design and purpose have been relocated to the Bases. The design features and system operation are also described in the FSAR. Changes to the Bases will be controlled by the provisions of the proposed Bases Control Process in Chapter 5 of the Technical Specifications. Changes to the FSAR will be controlled by the provisions of 10 CFR 50.59.

INSERT 1 for ITS 5.1

The Superintendent of Shift (SOS) shall be responsible for the control room command function. During any absence of the SOS from the control room while either unit is in MODE 1, 2, or 3, an individual with an active Senior Reactor Operator (SRO) license shall be designated to assume the control room command function. During any absence of the SOS from the control room while both units are in MODE 4 or 5, an individual with an active SRO license or Reactor Operator license shall be designated to assume the control room command function.

Specification 5.6

SURVEILLANCE REQUIREMENTS (Continued)

4.8.1.1.4 Reports - All diesel generator failures, valid or non-valid, shall be reported to the Commission pursuant to 10 CFR 50.73 or Specification 6.9.2, as applicable. If the number of failures in the last 100 valid tests, on a per nuclear unit basis, is ≥ 7, the report shall be supplemented to include the additional information recommended in Regulatory Position C.3.b of Regulatory Guide, 1.108, Revision 1, August 1977.

C

TABLE 3.3.6.4-1 (Continued)

POST ACCIDENT MONITORING INSTRUMENTATION

a) If either the primary or secondary indication is inoperable, the torus temperature will be monitored at least once per shift to observe any unexplained temperature increases which might be indicative of an open S/RV. With both the primary and secondary monitoring channels of an S/RV inoperable, either verify that the S/RV is closed through monitoring the backup low low set logic position indicators (2B21-N302 A-H and K-M) at least once per shift or restore sufficient inoperable channels such that no more than one S/RV has both primary and secondary channels inoperable within 7 days or be in at least hot shutdown within the next 12 hours.

b) With the number of operable channels less than required by the minimum channels operable requirements, initiate the pre-planned alternate method of monitoring the appropriate parameters within 72 hours and:

1. either restore the inoperable channel(s) to operable status within 7 da[illegible] f the event, or

5.6.7

2. prepare and submit a Special Report to NRC pursuant to Specification 6.[illegible] within 14 days following the event, outlining the action taken, the cause of the inoperability, a[illegible] the plans and schedule for restoring the system to operable status.

c) A channel contains two detectors: one for mid-range noble gas and one for high-range noble gas. Both detectors must be operable to consider the channel operable.

C

See Discussion of changes for ITS: 3.3.3.1, PAM Instrumentation, in Section 3.3.

Specification 5.6

UNIT 2 NO SIGNIFICANT HAZARDS DETERMINATION

L.11 CHANGE

Deleted.

NO SIGNIFICANT HAZARDS DETERMINATION
ITS: SECTION 5.6 - REPORTING REQUIREMENTS

There were no plant specific less restrictive changes identified for these Specifications.

NUREG 1433 COMPARISON DOCUMENT - SPECIFICATIONS

SURVEILLANCE REQUIREMENTS

---NOTE---
When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided feedwater and main turbine trip capability is maintained.
(high water level) (HP 3)

SURVEILLANCE		FREQUENCY
SR 3.3.2.2.1	Perform CHANNEL CHECK.	24 hours
SR 3.3.2.2.2 (P.1 - 1)	Perform CHANNEL FUNCTIONAL TEST.	~~[92]~~ days (P.1)
SR 3.3.2.2.3 (P.1 2)	Perform CHANNEL CALIBRATION. The Allowable Value shall be ≤ ~~[58.0]~~ 55.5 * U1 only / 56.5 * U1 only inches.	~~[18]~~ months (P.1)
SR 3.3.2.2.4 (P.1 3)	Perform LOGIC SYSTEM FUNCTIONAL TEST including ~~[valve]~~ actuation. (P.1)	~~[18]~~ months (P.1)

3.3 INSTRUMENTATION

3.3.3.1 Post Accident Monitoring (PAM) Instrumentation

LCO 3.3.3.1 The PAM instrumentation for each Function in Table 3.3.3.1-1 shall be OPERABLE.

APPLICABILITY: MODES 1 and 2.

ACTIONS

----------NOTES----------
1. LCO 3.0.4 is not applicable.

2. Separate Condition entry is allowed for each Function.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Functions with one required channel inoperable.	A.1 Restore required channel to OPERABLE status.	30 days
B. Required Action and associated Completion Time of Condition A not met.	B.1 Initiate action in accordance with Specification 5.~~9.2.c.~~ 6.7	Immediately
C. ----------NOTE---------- Not applicable to [hydrogen monitor] channels. ---------- One or more Functions with two required channels inoperable.	C.1 Restore all but one required channel to OPERABLE status.	7 days

(continued)

Table 3.3.7.1-1 (page 1 of 1)
[Main Control Room Environmental Control] System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION A.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Reactor Vessel Water Level – Low Low Low, Level 1	1,2,3,[a]	[2]	B	SR 3.3.7.1.1 SR 3.3.7.1.2 [SR 3.3.7.1.3] SR 3.3.7.1.4 SR 3.3.7.1.5	≥ [-113] inches
2. Drywell Pressure – High	1,2,3	[2]	B	SR 3.3.7.1.1 SR 3.3.7.1.2 [SR 3.3.7.1.3] SR 3.3.7.1.4 SR 3.3.7.1.5	≤ [1.92] psig
3. Main Steam Line Flow – High	1,2,3	[2 per MSL]	B	SR 3.3.7.1.1 SR 3.3.7.1.2 [SR 3.3.7.1.3] SR 3.3.7.1.4 SR 3.3.7.1.5	[138]% rated steam flow
4. Refueling Floor Area Radiation – High	1,2,3, [(a),(b)]	[1]	C	SR 3.3.7.1.1 SR 3.3.7.1.2 SR 3.3.7.1.4 SR 3.3.7.1.5	≤ [20] mR/hr
5. Control Room Air Inlet Radiation – High	1,2,3, (a),(b)	[1]	A	SR 3.3.7.1.1 SR 3.3.7.1.2 SR 3.3.7.1.3 SR 3.3.7.1.4	≤ [1] mR/hr

Moved to the LCO statement

Moved to the Applicability Statement

Moved to SR 3.3.7.1.3

(a) During CORE ALTERATIONS or operations with a potential for draining the reactor vessel.

(b) During movement of irradiated fuel assemblies in the secondary containment.

and during

Unit

Inherent in the SRs and Actions

moved to the Applicability Statement

3.3 INSTRUMENTATION

3.3.8.1 Loss of Power (LOP) Instrumentation

LCO 3.3.8.1 The LOP instrumentation for each Function in Table 3.3.8.1-1 shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3,
When the associated diesel generator is required to be OPERABLE by LCO 3.8.2, "AC Sources—Shutdown."

ACTIONS

NOTE
Separate Condition entry is allowed for each channel.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more channels inoperable for Functions 1 and 2.	A.1 Restore channel to ~~Place channel in trip.~~ OPERABLE status	1 hour
B. Required Action and associated Completion Time not met.	B.1 Declare associated ~~diesel generator (DG)~~ inoperable.	Immediately
B. One or more channels inoperable for Function 3.	B.1 Verify voltage on associated 4.16 kV bus is ≥ 3825 V.	Once per hour

SURVEILLANCE REQUIREMENTS

NOTES

1. Refer to Table 3.3.8.1-1 to determine which SRs apply for each LOP Function.

2. When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 2 hours provided the associated Function maintains DG initiation capability (i.e. (6) (P8) (for Functions 1 and 2) and annunciation capability (for Function 3). (P.26)

SURVEILLANCE		FREQUENCY
SR 3.3.8.1.1	Perform CHANNEL CHECK.	12 hours (P.1)
SR 3.3.8.1.2	Perform CHANNEL FUNCTIONAL TEST.	31 days
SR 3.3.8.1.3	Perform CHANNEL CALIBRATION.	~~{18}~~ months (P.1) (C)
SR 3.3.8.1.4	Perform LOGIC SYSTEM FUNCTIONAL TEST.	~~{18}~~ months

Table 3.3.8.1-1 (page 1 of 1)
Loss of Power Instrumentation

FUNCTION	REQUIRED CHANNELS PER BUS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. 4.16 kV Emergency Bus Undervoltage (Loss of Voltage)			
a. Bus Undervoltage	~~[2]~~	~~[SR 3.3.8.1.1]~~ SR 3.3.8.1.2 SR 3.3.8.1.3 SR 3.3.8.1.4	≥ [2800] V ~~and ≤ [ ] V~~
b. Time Delay	~~[2]~~	[SR 3.3.8.1.2] SR 3.3.8.1.3 SR 3.3.8.1.4	≥ ~~[ ] seconds and~~ ≤ [6.5] seconds
2. 4.16 kV Emergency Bus Undervoltage (Degraded Voltage)			
a. Bus Undervoltage	[2]	~~[SR 3.3.8.1.1]~~ SR 3.3.8.1.2 SR 3.3.8.1.3 SR 3.3.8.1.4	≥ [3280] V ~~and ≤ [ ] V~~
b. Time Delay	[2]	[SR 3.3.8.1.2] SR 3.3.8.1.3 SR 3.3.8.1.4	~~≥ [ ] seconds and~~ ≤ [21.5] seconds

≥1

3. 4.16 kV Emergency Bus Undervoltage Annunciation	1	SR 3.3.8.1.1 SR 3.3.8.1.2 SR 3.3.8.1.3 SR 3.3.8.1.4	≥ 3825 V
b. Time Delay	1	SR 3.3.8.1.2 SR 3.3.8.1.3 SR 3.3.8.1.4	≤ 60 seconds

P.11 P.35 P.35 P.35 P.35 P.70

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
F. One [required] [automatic load sequencer] inoperable. (P8)	-------REVIEWER'S NOTE------- This Condition may be deleted if the unit design is such that any sequencer failure mode will only affect the ability of the associated DG to power its respective safety loads following a loss of offsite power independent of, or coincident with, a Design Basis Event. ---------- F.1 Restore [required] [automatic load sequencer] to OPERABLE status.	[12] hours
G. Required Action and Associated Completion Time of Condition A, B, C, D, [or] E[, or F] not met. (P1)	G.1 Be in MODE 3. AND G.2 Be in MODE 4.	12 hours 36 hours
H. Three or more [required] AC sources inoperable [for reasons other than Condition E]. (Insert H 3.8.1) (P2)	H.1 Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.1.1	Verify correct breaker alignment and indicated power availability for each ~~{required}~~ offsite circuit.	7 days
SR 3.8.1.2	----------NOTES---------- 1. Performance of SR 3.8.1.~~2~~ satisfies this SR. 2. All DG starts may be preceded by an engine prelube period and followed by a warmup period prior to loading. 3. A modified DG start involving idling and gradual acceleration to synchronous speed may be used for this SR as recommended by the manufacturer. When modified start procedures are not used, the time, voltage, and frequency tolerances of SR 3.8.1.~~2~~ must be met. ---------- Verify each DG ~~starts~~ from standby conditions and achieves steady state voltage ≥ ~~{3740}~~ V and ≤ ~~{4580}~~ V and frequency ≥ ~~{58.8}~~ Hz and ≤ ~~{61.2}~~ Hz; and	31 days ~~As specified in Table 3.8.1-1~~

(continued)

Table 3.8.1-1
Diesel Generator Test Schedule

NUMBER OF FAILURES IN LAST 25 VALID TESTS(a)	FREQUENCY
≤ 3	31 days
≥ 4	7 days(b) (but ≥ 24 hours)

(a) Criteria for determining number of failures and valid tests shall be in accordance with Regulatory Position C.2.1 of Regulatory Guide 1.9, Revision 3, where the number of tests and failures is determined on a per DG basis.

(b) This test frequency shall be maintained until seven consecutive failure free starts from standby conditions and load and run tests have been performed. This is consistent with Regulatory Position [ ], of Regulatory Guide 1.9, Revision 3. If, subsequent to the 7 failure free tests, 1 or more additional failures occur such that there are again 4 or more failures in the last 25 tests, the testing interval shall again be reduced as noted above and maintained until 7 consecutive failure free tests have been performed.

[Note: If Revision 3 of Regulatory Guide 1.9 is not approved, the above table will be modified to be consistent with the existing version of Regulatory Guide 1.108, GL 84-15, or other approved guidance.]

P. 43

3.8 ELECTRICAL POWER SYSTEMS

3.8.2 AC Sources—Shutdown

LCO 3.8.2 The following AC electrical power sources shall be OPERABLE:

a. One qualified circuit between the offsite transmission network and the onsite Class 1E AC electrical power distribution subsystem(s) required by LCO 3.8.10, "Distribution Systems—Shutdown"; and

b. One diesel generator (DG) capable of supplying one division of the onsite Class 1E AC electrical power distribution subsystem(s) required by LCO 3.8.10;

APPLICABILITY: MODES 4 and 5,
During movement of irradiated fuel assemblies in the secondary containment.

(P7)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.2.4 Initiate action to restore [required] inverters to OPERABLE status.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.8.1	Verify correct inverter voltage, [frequency,] and alignments to [required] AC vital buses.	7 days

3.8 ELECTRICAL POWER SYSTEMS

3.8.8 Distribution Systems—Operating

LCO 3.8.8 [Division 1] and [Division 2] AC, DC, [and AC vital bus] electrical power distribution subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One AC electrical power distribution subsystem inoperable.	A.1 Restore AC electrical power distribution subsystems to OPERABLE status.	8 hours AND 16 hours from discovery of failure to meet LCO
B. One AC vital bus inoperable.	B.1 Restore AC vital bus distribution subsystems to OPERABLE status.	2 hours AND 16 hours from discovery of failure to meet LCO
C. One [station service] DC electrical power distribution subsystem inoperable.	C.1 Restore DC electrical power distribution subsystems to OPERABLE status.	2 hours AND 16 hours from discovery of failure to meet LCO

(continued)

INSERT LCO 3.8.7 (U1 VERSION)

The following AC and DC electrical power distribution subsystems shall be OPERABLE:

a. Unit 1 AC and DC electrical power distribution subsystems comprised of:

   1. 4160 V Essential Buses 1E, 1F, and 1G;

   2. 600 V Essential Buses 1C and 1D;

   3. 120/208 V Essential Cabinets 1A and 1B;

   4. 120/208 V Instrument Buses 1A and 1B;

   5. 125/250 V DC Station Service Buses 1A and 1B;

   6. DG DC Electrical Power Distribution Subsystems; and

b. Unit 2 AC and DC electrical power distribution subsystems needed to support equipment required to be OPERABLE by LCO 3.6.4.3, "Standby Gas Treatment (SGT) System," and LCO 3.8.1, "AC Sources - Operating."

INSERT LCO 3.8.7 (U2 VERSION)

The following AC and DC electrical power distribution subsystems shall be OPERABLE:

a. Unit 2 AC and DC electrical power distribution subsystems comprised of:

1. 4160 V Essential Buses 2E, 2F, and 2G;

2. 600 V Essential Buses 2C and 2D;

3. 120/208 V Essential Cabinets 2A and 2B;

4. 120/208 V Instrument Buses 2A and 2B;

5. 125/250 V DC Station Service Buses 2A and 2B;

6. DG DC Electrical Power Distribution Subsystems; and

b. Unit 1 AC and DC electrical power distribution subsystems needed to support equipment required to be OPERABLE by LCO 3.6.4.7, "Standby Gas Treatment (SGT) System," LCO 3.7.4, "Main Control Room Environmental Control (MCREC) System," LCO 3.7.5, "Control Room Air Conditioning (AC) System," and LCO 3.8.1, "AC Sources - Operating."

INSERT A/B 3.8.7

A. One or more required Unit 2 AC or DC electrical power subsystems inoperable.	A.1	Restore required Unit 2 AC and DC subsystem(s) to OPERABLE status.	7 days
B. One Unit 1 or swing bus DG DC electrical power distribution subsystems inoperable.	B.1	Restore DG DC electrical power distribution subsystem to OPERABLE status.	12 hours AND 16 hours from discovery of failure to meet LCO 3.8.7.a

HATCH UNIT 1, & UNIT 2

5.0 ADMINISTRATIVE CONTROLS

5.1 Responsibility

5.1.1 The [Plant Superintendent] shall be responsible for overall unit operation and shall delegate in writing the succession to this responsibility during his absence.

Also modified by BWOG-89 Item C.1

The [Plant Superintendent], or his designee, in accordance with approved administrative procedures, shall approve prior to implementation, each proposed test or experiment and proposed changes and modifications to unit systems or equipment that affect nuclear safety.

P.1 INSERT A

P.2 Superintendent of Shift (SOS)

5.1.2 The ~~[Shift Supervisor (SS)]~~ shall be responsible for the control room command function. A management directive to this effect, signed by the [highest level] of corporate or site management] shall be issued annually to all station personnel. During any absence of the ~~[SS]~~ from the control room while the unit is in MODE 1, 2, or 3, an individual with ~~a valid~~ Senior Reactor Operator (SRO) license shall be designated to assume the control room command function. During any absence of the ~~[SS]~~ from the control room while ~~the unit is~~ in MODE 4 or 5, an individual with ~~a valid~~ SRO license or Reactor Operator license shall be designated to assume the control room command function.

GP.1 SOS P.2

SOS P.2

an active GP.1

both units are P.31

either P.31

5.0 ADMINISTRATIVE CONTROLS

5.2 Organization

5.2.1 Onsite and Offsite Organizations

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

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

b. The ~~[Plant Superintendent]~~ shall be responsible for overall safe operation of the plant and shall have control over those onsite activities necessary for safe operation and maintenance of the plant;

c. The ~~[a specified corporate executive position]~~ shall have corporate responsibility for overall plant nuclear safety and shall take any measures needed to ensure acceptable performance of the staff in operating, maintaining, and providing technical support to the plant to ensure nuclear safety; and

d. The individuals who train the operating staff, carry out health physics, or perform quality assurance functions may report to the appropriate onsite manager; however, these individuals shall have sufficient organizational freedom to ensure their independence from operating pressures.

5.2.2 Unit Staff

The unit staff organization shall ~~be as follows~~:

a. Each on-duty shift shall be composed of at least the minimum shift crew composition shown in Table 5.2.2-1.

(continued)

INSERT B FOR NUREG 5.2.2

a. A plant equipment operator (PEO) shall be assigned to each reactor containing fuel and an additional PEO shall be assigned for each control room from which a reactor is operating in MODE 1, 2, or 3. With both units shutdown or defueled, a total of three PEOs for the two units is required.

c. Shift crew composition may be less than the minimum requirement of 10 CFR 50.54(m)(2)(i) and 5.2.2.a for a period of time not to exceed 2 hours in order to accommodate unexpected absence of on duty shift crew members provided immediate action is taken to restore the shift crew composition to within the minimum requirements.

The Minimum Shift Crew Composition shall be in accordance with 10 CFR 50.54(m)(2)(i). P.32

A total of three plant equipment operators (PEOs) for the two units is required in all conditions. At least one of the required PEOs shall be assigned to each reactor containing fuel.

P.31

5.6 Reporting Requirements

~~5.9.2~~ ~~Special Reports (continued)~~

an individual basis for each unit and their preparation and submittal are designated in the Technical Specifications.

Special Reports shall be submitted in accordance with 10 CFR 50.4 within the time period specified for each report.

The following Special Reports shall be submitted:

a. In the event an ECCS is actuated and injects water into the RCS in MODE 1, 2, or 3, a Special Report shall be prepared and submitted within 90 days describing the circumstances of the actuation and the total accumulated actuation cycles to date. The current value of the usage factor for each affected safety injection nozzle shall be provided in this Special Report whenever its value exceeds 0.70.

b. If an individual emergency diesel generator (EDG) experiences four or more valid failures in the last 25 demands, these failures and any nonvalid failures experienced by that EDG in that time period shall be reported within 30 days. Reports on EDG failures shall include the information recommended in Regulatory Guide 1.9, Revision 3, Regulatory Position C.5, or existing Regulatory Guide 1.108 reporting requirement.

c. When a ~~Special~~ Report is required by ~~Condition B or G of~~ LCO 3.3.~~[3.1]~~, "Post Accident Monitoring (PAM) Instrumentation," a report shall be submitted within the following 14 days. The report shall outline the preplanned alternate method of monitoring, the cause of the inoperability, and the plans and schedule for restoring the instrumentation channels of the Function to OPERABLE status.

5.6.7 Post Accident Monitoring (PAM) Instrumentation Report

5.0 ADMINISTRATIVE CONTROLS

5.10 Record Retention

5.10.1 The following records shall be retained for at least 3 years:

a. All License Event Reports required by 10 CFR 50.73;

b. Records of changes made to the procedures required by Specification 5.7.1.1; and

c. Records of radioactive shipments.

5.10.2 The following records shall be retained for at least 5 years:

a. Records and logs of unit operation covering time intervals at each power level;

b. Records and logs of principal maintenance activities—inspections, repair, and replacement of principal items of equipment related to nuclear safety;

c. Records of surveillance activities, inspections, and calibrations required by the Technical Specifications (TS) [and the Fire Protection Program];

d. Records of sealed source and fission detector leak tests and results; and

e. Records of annual physical inventory of all sealed source material of record.

5.10.3 The following records shall be retained for the duration of the unit Operating License:

a. Records and drawing changes reflecting unit design modifications made to systems and equipment described in the FSAR;

b. Records of new and irradiated fuel inventory, fuel transfers, and assembly burnup histories;

c. Records of radiation exposure for all individuals entering radiation control areas;

GP.1

(continued)

NUREG 1433 COMPARISON DOCUMENT - BASES

BASES

LCO

~~13.~~ Suppression Pool Water Temperature (continued)

that there is a group of sensors within a 30 ft line of sight of each relief valve discharge location.

Thus, six groups of sensors are sufficient to monitor each relief valve discharge location. Each group of four sensors includes two sensors for normal suppression pool temperature monitoring and two sensors for PAM. The outputs for the PAM sensors are recorded on four independent recorders in the control room (channels A and C are redundant to channels B and D, respectively). All four of these recorders must be OPERABLE to furnish two channels of PAM indication for each of the relief valve discharge locations. These recorders are the primary indication used by the operator during an accident. Therefore, the PAM Specification deals specifically with this portion of the instrument channels.

APPLICABILITY

The PAM instrumentation LCO is applicable in MODES 1 and 2. These variables are related to the diagnosis and preplanned actions required to mitigate DBAs. The applicable DBAs are assumed to occur in MODES 1 and 2. In MODES 3, 4, and 5, plant conditions are such that the likelihood of an event that would require PAM instrumentation is extremely low; therefore, PAM instrumentation is not required to be OPERABLE in these MODES.

ACTIONS

Note 1 has been added to the ACTIONS to exclude the MODE change restriction of LCO 3.0.4. This exception allows entry into the applicable MODE while relying on the ACTIONS even though the ACTIONS may eventually require plant shutdown. This exception is acceptable due to the passive function of the instruments, the operator's ability to diagnose an accident using alternative instruments and methods, and the low probability of an event requiring these instruments.

Note 2 has been provided to modify the ACTIONS related to PAM instrumentation channels. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent ~~trains~~ divisions, subsystems, components, or variables expressed in the Condition discovered to be inoperable or

(continued)

BASES

ACTIONS (continued)

not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable PAM instrumentation channels provide appropriate compensatory measures for separate Functions. As such, a Note has been provided that allows separate Condition entry for each inoperable PAM Function.

A.1

When one or more Functions have one required channel that is inoperable, the required inoperable channel must be restored to OPERABLE status within 30 days. The 30 day Completion Time is based on operating experience and takes into account the remaining OPERABLE channels (or, in the case of a Function that has only one required channel, other non-Regulatory Guide 1.97 instrument channels to monitor the Function), the passive nature of the instrument (no critical automatic action is assumed to occur from these instruments), and the low probability of an event requiring PAM instrumentation during this interval.

B.1

If a channel has not been restored to OPERABLE status in 30 days, this Required Action specifies initiation of action in accordance with Specification 5.~~9.2.c, "Special Reports,"~~ which requires a written report ~~approved by the [onsite review committee]~~ to be submitted to the NRC. This report discusses the results of the root cause evaluation of the inoperability and identifies proposed restorative actions. This action is appropriate in lieu of a shutdown requirement, since alternative actions are identified before loss of functional capability, and given the likelihood of plant conditions that would require information provided by this instrumentation.

C.1

When one or more Functions have two or more required channels that are inoperable (i.e., two channels inoperable in the same

(continued)

B 3.3 INSTRUMENTATION

B 3.3.8.1 Loss of Power (LOP) Instrumentation

BASES

BACKGROUND

Successful operation of the required safety functions of the Emergency Core Cooling Systems (ECCS) is dependent upon the availability of adequate power sources for energizing the various components such as pump motors, motor operated valves, and the associated control components. The LOP instrumentation monitors the 4.16 kV emergency buses. Offsite power is the preferred source of power for the 4.16 kV emergency buses. If the monitors determine that insufficient power is available, the buses are disconnected from the offsite power sources and connected to the onsite diesel generator (DG) power sources.

Each 4.16 kV emergency bus has its own independent LOP instrumentation and associated trip logic. The voltage for each bus is monitored at two levels, which can be considered as two different undervoltage Functions: Loss of Voltage and 4.16 kV Emergency Bus Undervoltage Degraded Voltage. Each Function causes various bus transfers and disconnects. Each Function is monitored by two undervoltage relays for each emergency bus, whose outputs are arranged in a two-out-of-two logic configuration (Ref. 1). The channels include electronic equipment (e.g., trip units) that compares measured input signals with pre-established setpoints. When the setpoint is exceeded, the channel output relay actuates, which then outputs a LOP trip signal to the trip logic.

for all affected components except the DGs. The DG start logic configuration is one-out-of-two.

P.59 P.70 P.70

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The LOP instrumentation is required for Engineered Safety Features to function in any accident with a loss of offsite power. The required channels of LOP instrumentation ensure that the ECCS and other assumed systems powered from the DGs, provide plant protection in the event of any of the Reference 2, 3, and 4 analyzed accidents in which a loss of offsite power is assumed. The initiation of the DGs on loss of offsite power, and subsequent initiation of the ECCS, ensure that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Accident analyses credit the loading of the DG based on the loss of offsite power during a loss of coolant accident. The diesel starting and loading times have been included in the delay time associated with each safety system component requiring DG supplied power following a loss of offsite power.

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

The OPERABILITY of the LOP instrumentation is dependent upon the OPERABILITY of the individual instrumentation channel Functions specified in Table 3.3.8.1-1. Each Function must have a required number of OPERABLE channels per 4.16 kV emergency bus, with their setpoints within the specified Allowable Values. A channel is inoperable if its actual trip setpoint is not within its required Allowable Value. The ~~design~~ setpoint is calibrated consistent with applicable ~~setpoint methodology assumptions.~~

The Allowable Values are specified for each Function in the Table. Nominal trip setpoints are specified in the setpoint calculations. The nominal setpoints are selected to ensure that the setpoints do not exceed the Allowable Value between CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within the Allowable Value, is acceptable. Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter (e.g., degraded voltage), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., trip ~~unit~~) changes state. ~~The analytic limits are derived from the limiting values of the process parameters obtained from the safety analysis.~~ The Allowable Values are derived from the analytic limits, corrected for calibration, process, and some of the instrument errors. The trip setpoints are then determined accounting for the remaining instrument errors (e.g., drift). The trip setpoints derived in this manner provide adequate protection because instrumentation uncertainties, process effects, calibration tolerances, instrument drift, and severe environment errors (for channels that must function in harsh environments as defined by 10 CFR 50.49) are accounted for.

(continued)

INSERT 1 3.3.8.1 Background Section (page B 3.3-219)

Each 4.16 kV emergency bus has its own independent LOP alarm instrumentation to provide an anticipatory alarm and the initiation of corrective measures to restore emergency bus voltages. The alarms are set higher than the LOP trip relays. The alarm setpoints are approximately midway between the calculated minimum expected voltage and the calculated minimum required voltage, based on the maximum expected operating; i.e., non-LOCA, load conditions. The alarm setpoints signify that adequate voltage is available for normal operations. The LOP anticipatory alarms provide a total time delay of 60 seconds to reduce the possibility of nuisance alarms, while permitting prompt detection of potential low voltage conditions.

C

UNIT 1 AND UNIT 2

INSERT 6 3.3.8.1 Background Section (page B 3.3-217)

Each 4.16 kV emergency bus has a dedicated low voltage annunciator fed by two relays and their associated time delays. The logic for the annunciation function is arranged in a one-out-of-two configuration.

C

UNIT 1 AND UNIT 2

INSERT 2 3.3.8.1 Applicable Safety Analysis Section(page B 3.3-220)

The LOP alarm instrumentation is required to initiate manual actions to restore the 4.16 kV emergency bus voltages or to initiate a plant shutdown. The required channels of LOP alarm instrumentation ensures the initiation of manual actions to protect the ECCS and other assumed systems from degraded voltage without initiating an unnecessary automatic disconnect from the preferred offsite power source. The occurrence of an undervoltage degraded voltage condition credits the manual actions to mitigate the condition and ensure plant safety is maintained.

INSERT 3 3.3.8.1 Applicable Safety Analysis Section (page B 3.3-300)

The 4.16 kV undervoltage degraded voltage trip setpoints were determined in accordance with the NRC staff positions contained in an NRC letter dated June 2, 1977, except that manual actions are credited for restoring bus voltages or initiating a plant shutdown in the range of 78.8 to 92% of 4.16 kV. The undervoltage degraded voltage setpoint represents a point on the inverse time characteristic curve for the relay. The anticipatory alarm setpoints are approximately midway between the calculated minimum expected voltage and the calculated minimum required voltage, based on maximum expected operating; i.e., non-LOCA, conditions.

(UNIT 1 AND UNIT 2

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The specific Applicable Safety Analyses, LCO, and Applicability discussions are listed below on a Function by Function basis.

1. 4.16 kV Emergency Bus Undervoltage (Loss of Voltage)

Loss of voltage on a 4.16 kV emergency bus indicates that offsite power may be completely lost to the respective emergency bus and is unable to supply sufficient power for proper operation of the applicable equipment. Therefore, the power supply to the bus is transferred from offsite power to DG power when the voltage on the bus drops below the Loss of Voltage Function Allowable Values (loss of voltage with a short time delay). This ensures that adequate power will be available to the required equipment.

The Bus Undervoltage Allowable Values are low enough to prevent inadvertent power supply transfer, but high enough to ensure that power is available to the required equipment. The Time Delay Allowable Values are long enough to provide time for the offsite power supply to recover to normal voltages, but short enough to ensure that power is available to the required equipment.

Two channels of 4.16 kV Emergency Bus Undervoltage (Loss of Voltage) Function per associated emergency bus are only required to be OPERABLE when the associated DG is required to be OPERABLE to ensure that no single instrument failure can preclude the DG function. (Two channels input to each of the three DGs.) Refer to LCO 3.8.1, "AC Sources—Operating," and 3.8.2, "AC Sources--Shutdown," for Applicability Bases for the DGs.

2. 4.16 kV Emergency Bus Undervoltage (Degraded Voltage)

A reduced voltage condition on a 4.16 kV emergency bus indicates that, while offsite power may not be completely lost to the respective emergency bus, available power may be insufficient for starting large ECCS motors without risking damage to the motors that could disable the ECCS function. Therefore, power supply to the bus is transferred from offsite power to onsite DG power when the voltage on the bus drops below the Degraded Voltage Function Allowable Values

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2. 4.16 kV Emergency Bus Undervoltage (Degraded Voltage) (continued)

(degraded voltage with a time delay). This ensures that adequate power will be available to the required equipment.

The Bus Undervoltage Allowable Values are low enough to prevent inadvertent power supply transfer, but high enough to ensure that sufficient power is available to the ~~required equipment~~. The Time Delay Allowable Values are long enough to provide time for the offsite power supply to recover to normal voltages, but short enough to ensure that sufficient power is available to the required equipment.

Two channels of 4.16 kV Emergency Bus Undervoltage (Degraded Voltage) Function per associated bus are only required to be OPERABLE when the associated DG is required to be OPERABLE to ensure that no single instrument failure can preclude the DG function. (Two channels input to each of the three emergency buses and DGs.) Refer to LCO 3.8.1 and LCO 3.8.2 for Applicability Bases for the DGs.

3.

ACTIONS

A Note has been provided to modify the ACTIONS related to LOP instrumentation channels. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent ~~trains~~, subsystems, components, or variables expressed in the Condition, discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable LOP instrumentation channels provide appropriate compensatory measures for separate inoperable channels. As such, a Note has been provided that allows separate Condition entry for each inoperable LOP instrumentation channel.

A.1

With one or more channels of a Function inoperable, the Function is not capable of performing the intended function. Therefore, only 1 hour is allowed to restore the inoperable

(continued)

INSERT 4 3.3.8.1 Applicable Safety Analysis Section (page B 3.3-222)

Manual actions are credited in the range of 78.8 to 92% of 4.16 kV to restore bus voltages or to initiate a plant shutdown. The range specified for manual actions indicates that sufficient power is available to the large ECCS motors; however, sufficient voltage for equipment at lower voltages required for LOCA conditions may not be available.

C

UNIT 1 AND UNIT 2

INSERT 5 3.3.8.1 Applicable Safety Analysis Section(page B 3.3-222)

3. 4.16 kV Emergency Bus Undervoltage (Anticipatory Alarms)

A reduced voltage condition on a 4.16 kV emergency bus indicated that, while offsite power is adequate for normal operating conditions, available power may be marginal for some equipment required for LOCA conditions. Therefore, the anticipatory alarms actuate when the 4.16 kV bus voltages approach the minimum required voltage for normal; i.e., non-LOCA, conditions. This ensures that manual actions will be initiated to restore the bus voltages or to initiate a plant shutdown.

One channel of the 4.16 kV emergency bus undervoltage (Anticipatory Alarm) function per the associated bus are only required to be OPERABLE when the associated DG is required to be OPERABLE. (Two channels input to each of the three emergency buses.)

BASES

ACTIONS

A.1 (continued)

channel to OPERABLE status. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel must be placed in the tripped condition per Required Action A.1. Placing the inoperable channel in trip would conservatively compensate for the inoperability, restore capability to accommodate a single failure (within the LOP instrumentation), and allow operation to continue. Alternately, if it is not desired to place the channel in trip (e.g., as in the case where placing the channel in trip would result in a DG initiation), Condition B must be entered and its Required Action taken.

P.67

The Required Action does not allow placing a channel in trip since this action will result in a DG initiation.

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. The 1 hour Completion Time is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

INSERT C → P.70

C B.1 P.70

C

If any Required Action and associated Completion Time are not met, the associated Function is not capable of performing the intended function. Therefore, the associated DG(s) is declared inoperable immediately. This requires entry into applicable Conditions and Required Actions of LCO 3.8.1 and LCO 3.8.2, which provide appropriate actions for the inoperable DG(s).

SURVEILLANCE REQUIREMENTS

As noted at the beginning of the SRs, the SRs for each LOP instrumentation Function are located in the SRs column of Table 3.3.8.1-1.

The Surveillances are modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 2 hours provided the associated Function maintains DG initiation capability. Upon completion of the Surveillance, or expiration of the 2 hour allowance, the channel must be

P.8 → 6 → 2 hours

INSERT A → P.26

6 P.8

(continued)

P.26 → (for Functions 1 and 2) and annunciation capability (for Function 3).

C

BASES

P.26 defined for Function 3 to be a comparison of the annunciator status to the bus voltage and an annunciator test confirming the annunciator is capable of lighting and sounding.

SURVEILLANCE REQUIREMENTS (continued)

returned to OPERABLE status or the applicable Condition entered and Required Actions taken.

P.26 or a failure of annunciation

SR 3.3.8.1.1

Performance of the CHANNEL CHECK once every 12 hours ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the instrument channels could be an indication of excessive instrument drift in one of the channels or something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

P.26 or an annunciator failure

P.70 Agreement criteria are determined by the plant staff based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the match criteria, it may be an indication that the instrument has drifted outside its limit.

The Frequency is based upon operating experience that demonstrates channel failure is rare. Thus, performance of the CHANNEL CHECK ensures that undetected outright channel failure is limited to 12 hours. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with channels required by the LCO.

P.26 or annunciator

SR 3.3.8.1.2

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function.

(P.1) INSERT B

The Frequency of 31 days is based on operating experience with regard to channel OPERABILITY and drift, which demonstrates that failure of more than one channel of a given Function in any 31 day interval is a rare event.

(continued)

INSERT C ACTIONS (continued) (page B 3.3-203)

Each 4.16 kV bus has a dedicated annunciator fed by two relays and their associated time delays in a one-out-of-two logic configuration. Only one relay and its associated time delay is required to be OPERABLE. Therefore, the loss of the required relay or time delay renders Function 3 incapable of performing the intended function. Since the intended function is to alert personnel to a lowering voltage condition and the voltage reading is available for each bus on the control room front panels, the Required Action is verification of the voltage to be above the annunciator setpoint (nominal) hourly.

UNIT 1 AND UNIT 2

INSERT A for proposed BASES B 3.3.8.1

~~The~~ Function 1 and 2 maintains DG initiation capability, provided two DGs can be initiated by the Function.

C

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.8.1.3

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations, ~~Measurement and setpoint error historical determinations must be performed~~ consistent with the plant specific setpoint methodology. ~~The channel shall be left calibrated consistent with the assumptions of the setpoint methodology~~.

If the as found setpoint is not within its required Allowable Value, the plant specific setpoint methodology may be revised, as appropriate, if the history and all other pertinent information indicate a need for the revision. ~~The As-~~ setpoint shall be ~~left set~~ consistent with the assumptions of the current plant specific setpoint methodology.

The Frequency is based upon the assumption of ~~an 18 month calibration interval in the determination of~~ the magnitude of equipment drift in the setpoint analysis.

SR 3.3.8.1.4

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required actuation logic for a specific channel. The system functional testing performed in LCO 3.8.1 and LCO 3.8.2 overlaps this Surveillance to provide complete testing of the assumed safety functions.

The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at the 18 month Frequency.

REFERENCES

1. FSAR, ~~Figure [ ]~~. Section 8.3.1 * U2 only
2. FSAR, Section ~~[5.2]~~. Section 8.4 * U1 only
   4.8 * U1 only

(continued)

BASES

REFERENCES (continued)

3. FSAR, Section 6.3.

4. FSAR, Chapter 15.

Insert R.14

BASES

BACKGROUND (continued)

DG 1B has the following ratings:

a. 2850 kW—~~continuous~~;

b. 3250 kW—168 hours.

APPLICABLE SAFETY ANALYSES

The initial conditions of DBA and transient ~~analyses~~ in the FSAR, ~~Chapter 6~~ (Ref. 4) and ~~Chapter 15~~ (Ref. 5), assume ESF systems are OPERABLE. The AC electrical power sources are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System (RCS), and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; ~~Section 3.4, Reactor Coolant System (RCS)~~; and Section 3.6, Containment Systems.

The OPERABILITY of the AC electrical power sources is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This includes maintaining the onsite or offsite AC sources OPERABLE during accident conditions in the event of:

a. An assumed loss of all offsite power ~~or~~ all onsite AC power; ~~and~~

b. ~~A~~ worst case single failure.

AC sources satisfy Criterion 3 of the NRC Policy Statement.

LCO

Two qualified circuits between the offsite transmission network and the onsite ~~Class 1E~~ Distribution System and three separate and independent DGs (2A, 2C, and 1B) ensure availability of the required power to shut down the reactor and maintain it in a safe shutdown condition after an anticipated operational occurrence (AOO) or a postulated DBA.

Qualified offsite circuits are those that are described in the FSAR, and are part of the licensing basis for the unit.

(continued)

BASES

LCO (continued) ~~[In addition, [one required automatic load sequencer per ESF bus] shall be OPERABLE.]~~

Each offsite circuit must be capable of maintaining rated frequency and voltage, and accepting required loads during an accident, while connected to the ESF buses. Each offsite circuit consists of incoming breaker and disconnect to the respective 2C and 2D SATs, the 2C and 2D transformers, and the respective circuit path including feeder breakers to 4.16 kV ESF buses. Feeder breakers from each circuit are ~~required to the 2F ESF bus;~~ however, if 2C SAT is connected to ESF bus 2E (or 2G) and 2D SAT is connected to 2G (or 2E), the remaining breakers to 2E and 2G are not required.

Each DG must be capable of starting, accelerating to rated speed and voltage, and connecting to its respective ESF bus on detection of bus undervoltage. This sequence must be accomplished within 12 seconds. Each DG must also be capable of accepting required loads within the assumed loading sequence intervals, and must continue to operate until offsite power can be restored to the ESF buses. These capabilities are required to be met from a variety of initial conditions, such as DG in standby with the engine hot, DG in standby with the engine at ambient condition, ~~and DG operating in parallel test mode.~~

Proper sequencing of loads, including tripping of nonessential loads, is a required function for DG OPERABILITY.

The AC sources must be separate and independent (to the extent possible) of other AC sources. For the DGs, the separation and independence are complete. For the offsite AC sources, the separation and independence are to the extent practical. A circuit may be connected to more than one ESF bus, with ~~fast~~ transfer capability to the other circuit OPERABLE, and not violate separation criteria. A circuit that is not connected to an ESF bus is required to have OPERABLE ~~fast~~ transfer ~~interlock mechanisms~~ to at least two ESF buses to support OPERABILITY of that circuit.

APPLICABILITY The AC sources ~~[and sequencers]~~ are required to be OPERABLE in MODES 1, 2, and 3 to ensure that:

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.2 and SR 3.8.1.7 (continued)

(see Note 3 of SR 3.8.1.2), when a modified start procedure as described above is used. If a modified start is not used, the 12 second start requirement of SR 3.8.1.7 applies.

Since SR 3.8.1.7 does requires a 12 second start, it is more restrictive than SR 3.8.1.2, and it may be performed in lieu of SR 3.8.1.2. This procedure is the intent of Note 1 of SR 3.8.1.2.

The normal 31 day Frequency for SR 3.8.1.2 (see Table 3.8.1-1, "Diesel Generator Test Schedule") is consistent with Regulatory Guide 1.9 (Ref. 3). The 184 day Frequency for SR 3.8.1.7 is a reduction in cold testing consistent with Generic Letter 84-15 (Ref. 7). These Frequencies provide adequate assurance of DG OPERABILITY, while minimizing degradation resulting from testing.

SR 3.8.1.3

This Surveillance verifies that the DGs are capable of synchronizing and accepting greater than or equal to the equivalent of the maximum expected accident loads. A minimum run time of 60 minutes is required to stabilize engine temperatures, while minimizing the time that the DG is connected to the offsite source.

Although no power factor requirements are established by this SR, the DG is normally operated at a power factor between [0.8 lagging] and [1.0]. The [0.8] value is the design rating of the machine, while [1.0] is an operational limitation, [to ensure circulating currents are minimized]. The load band is provided to avoid routine overloading of the DG. Routine overloading may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY.

The normal 31 day Frequency for this Surveillance (see Table 3.8.1-1) is consistent with Regulatory Guide 1.9 (Ref. 3).

(continued)

BASES

Note 6 modifies the Surveillance by stating that starting transients above the upper voltage limit do not invalidate this test.

SURVEILLANCE REQUIREMENTS

SR 3.8.1.3 ~~(continued)~~

Note ~~1~~ 5 modifies this Surveillance to indicate that diesel engine runs for this Surveillance may include gradual loading, as recommended by the manufacturer, so that mechanical stress and wear on the diesel engine are minimized.

Note ~~2~~ 7 modifies this Surveillance by stating that momentary transients because of changing bus loads do not invalidate this test. ~~Similarly, momentary power factor transients above the limit do not invalidate the test.~~

Note ~~3~~ 8 indicates that this Surveillance ~~should~~ is required to be conducted on only one DG at a time in order to avoid common cause failures that might result from offsite circuit or grid perturbations.

~~Note 4 stipulates a prerequisite requirement for performance of this SR. A successful DG start must precede this test to credit satisfactory performance.~~

Insert SR 3.8.1.2 Notes 5-8 (Rev 13 3.8-17)

SR 3.8.1.~~4~~ 3

This SR provides verification that the level of fuel oil in the day tank ~~[and engine mounted tank]~~ is at or above the level at which fuel oil is automatically added. The level is expressed as an equivalent volume in gallons, and is selected to ensure adequate fuel oil for a minimum of 1 hour of DG operation at full load plus 10%.

The actual amount required to meet this SR (xxx gallons) will provide approximately 3.5 hours of DG operation at full load.

The 31 day Frequency is adequate to ensure that a sufficient supply of fuel oil is available, since low level alarms are provided and ~~facility~~ operators would be aware of any large uses of fuel oil during this period.

SR 3.8.1.~~5~~ 4

Microbiological fouling is a major cause of fuel oil degradation. There are numerous bacteria that can grow in fuel oil and cause fouling, but all must have a water environment in order to survive. Removal of water from the fuel oil day ~~[and engine mounted]~~ tanks once every ~~[31]~~ 92 days eliminates the necessary environment for bacterial survival.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.18 (continued)

~~acknowledges that~~ credit may be taken for unplanned events that satisfy this SR.

Insert SR 3.8.1.16

~~Reviewer's Note: The above MODE restrictions may be deleted if it can be demonstrated to the staff, on a plant specific basis, that performing the SR with the reactor in any of the restricted MODES can satisfy the following criteria, as applicable:~~

~~a. Performance of the SR will not render any safety system or component inoperable;~~

~~b. Performance of the SR will not cause perturbations to any of the electrical distribution systems that could result in a challenge to steady state operation or to plant safety systems; and~~

~~c. Performance of the SR, or failure of the SR, will not cause, or result in, an AOO with attendant challenge to plant safety systems.~~

SR 3.8.1.~~18~~17

In the event of a DBA coincident with a loss of offsite power, the DGs are required to supply the necessary power to ESF systems so that the fuel, RCS, and containment design limits are not exceeded.

This Surveillance demonstrates DG operation, as discussed in the Bases for SR 3.8.1.~~11~~9, during a loss of offsite power actuation test signal in conjunction with an ECCS initiation signal. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the DG system to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

Insert SR 3.8.1.17 (to pg B 3.8-32)

The Frequency of ~~[~~18 months~~]~~ takes into consideration plant conditions required to perform the Surveillance and is intended to be consistent with an expected fuel cycle length of ~~[~~18 months~~]~~.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.1.~~19~~ (continued)

This SR is modified by ~~three~~ two Notes. The reason for Note 1 is to minimize wear and tear on the DGs during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil being continuously circulated and temperature maintained consistent with manufacturer recommendations. The reason for Note 2 is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. ~~Note 3 acknowledges that credit may be taken for~~ unplanned events that satisfy this SR.

SR 3.8.1.~~20~~

This Surveillance demonstrates that the DG starting independence has not been compromised. Also, this Surveillance demonstrates that each engine can achieve proper speed within the specified time when the DGs are started simultaneously.

The 10 year Frequency is consistent with the recommendations of Regulatory Guide 1.108 (Ref. 9), ~~paragraph 2.b, and Regulatory Guide 1.137 (Ref. 10), paragraph C.2.f.~~ This SR is modified by a Note. The reason for the Note is to minimize wear on the DG during testing. For the purpose of this testing, the DGs must be started from standby conditions, that is, with the engine coolant and oil continuously circulated and temperature maintained consistent with manufacturer recommendations. It is permissible to place all three DGs in test simultaneously, for the performance of this Surveillance.

~~Diesel Generator Test Schedule~~

The DG test schedule (Table 3.8.1-1) implements the recommendations of Revision 3 to Regulatory Guide 1.9 (Ref. 3). The purpose of this test schedule is to provide timely test data to establish a confidence level associated with the goal to maintain DG reliability at > 0.95 per test.

According to Regulatory Guide 1.9 (Ref. 3), Revision 3, each DG unit should be tested at least once every 31 days. Whenever a DG has experienced 4 or more valid failures in the last 25 valid tests, the maximum time between tests is

(continued)

BASES

SURVEILLANCE REQUIREMENTS

Diesel Generator Test Schedule (continued)

reduced to 7 days. Four failures in 25 valid tests is a failure rate of 0.16, or the threshold of acceptable DG performance, and hence may be an early indication of the degradation of DG reliability. When considered in the light of a long history of tests, however, 4 failures in the last 25 valid tests may only be a statistically probable distribution of random events. Increasing the test Frequency allows a more timely accumulation of additional test data upon which to base judgment of the reliability of the DG. The increased test Frequency must be maintained until seven consecutive failure free tests have been performed.

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The Frequency for accelerated testing is 7 days, but no less than 24 hours. Therefore, the interval between tests should be no less than 24 hours, and no more than 7 days. A successful test at an interval of less than 24 hours should be considered an invalid test and not count towards the seven consecutive failure free starts. A test interval in excess of 7 days constitutes a failure to meet SRs.

REFERENCES

P1 P29

1. 10 CFR 50, Appendix A, GDC 17.
2. FSAR, Section [8.2] and 8.3
3. Regulatory Guide 1.9,
4. FSAR, Chapter [6].
5. FSAR, Chapter [15].
6. Regulatory Guide 1.93,
7. Generic Letter 84-15.
8. 10 CFR 50, Appendix A, GDC 18.
9. Regulatory Guide 1.108,
10. Regulatory Guide 1.137,
11. ~~ANSI C84.1, 1982.~~

(continued)

BASES

REFERENCES (continued)

12. ~~FSAR, Section [6.3].~~

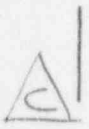
13. ~~ASME Boiler and Pressure Vessel Code, Section XI.~~

14. IEEE Standard 308, ~~-1980.~~

INSERT Ref

Unit 2 ... 13>
Unit 1 ... 14>

NRC No. 93-102, "Final Policy Statement on Technical Specification Improvements," July 23, 1993.



(R1)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.8.8.1 (continued)

closed and AC vital buses energized from the inverter. The verification of proper voltage and frequency output ensures that the required power is readily available for the instrumentation connected to the AC vital buses. The 7 day Frequency takes into account the redundant capability of the inverters and other indications available in the control room that alert the operator to inverter malfunctions.

REFERENCES

1. FSAR, Chapter [6].

2. FSAR, Chapter [15].

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.9 Distribution Systems—Operating

BASES

BACKGROUND

The onsite Class 1E AC and DC electrical power distribution system is divided into redundant and independent AC, DC, ~~and AC vital bus~~ electrical power distribution subsystems.

The primary AC distribution system consists of three 4.16 kV Engineered Safety Feature (ESF) buses each having an offsite source of power as well as a dedicated onsite diesel generator (DG) source. Each 4.16 kV ESF bus is normally connected to a normal source startup auxiliary transformer (SAT) (2D). During a loss of the normal offsite power source to the 4.16 kV ESF buses, the alternate supply breaker from SAT 2C attempts to close. If all offsite sources are unavailable, the onsite emergency DGs supply power to the 4.16 kV ESF buses.

The secondary plant distribution system includes 600 VAC emergency buses 2C and 2D and associated load centers, and transformers.

~~The 120 VAC vital buses 2YV1, 2YV2, 2YV3, and 2YV4 are arranged in four load groups and are normally powered from DC. The alternate power supply for the vital buses is a Class 1E constant voltage source transformer powered from the same division as the associated inverter, and its use is governed by LCO 3.8.7, "Inverters—Operating." Each constant voltage source transformer is powered from AC.~~

There are two independent 125/250 VDC station service electrical power distribution subsystems and three independent 125 VDC DG electrical power distribution subsystems that support the necessary power for ESF functions.

The list of all distribution buses is presented in ~~Table B 3.8.9-1~~ LCO 3.8.7.

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in the FSAR, Chapter [6] (Ref. 1) and Chapter [15] (Ref. 2), assume ESF systems are OPERABLE. The

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

AC and DC electrical power distribution systems are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System, and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.4, Reactor Coolant System (RCS); and Section 3.6 Containment Systems.

The OPERABILITY of the AC, DC, and AC vital bus electrical power distribution subsystems is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This includes maintaining distribution systems OPERABLE during accident conditions in the event of:

a. An assumed loss of all offsite power or all onsite AC electrical power; and

b. A worst case single failure.

The AC and DC electrical power distribution system satisfies Criterion 3 of the NRC Policy Statement. (Ref. 4)

LCO

The required electrical power distribution subsystems listed in Table B 3.8.9-1 ensure the availability of AC, DC, and AC vital bus electrical power for the systems required to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence (AOO) or a postulated DBA. The AC, DC, and AC vital bus electrical power distribution subsystems are required to be OPERABLE.

Maintaining the [Division 1 and 2] AC, DC, and AC vital bus electrical power distribution subsystems OPERABLE ensures that the redundancy incorporated into the design of ESF is not defeated. Therefore, a single failure within any system or within the electrical power distribution subsystems will not prevent safe shutdown of the reactor.

The AC, DC, and AC vital bus electrical power distribution subsystems require the associated buses and electrical circuits to be energized to their proper voltages.

(continued)

BASES

LCO (continued)

In addition, tie breakers between redundant safety related AC, DC, and AC vital bus power distribution subsystems, if they exist, must be open. This prevents any electrical malfunction in any power distribution subsystem from propagating to the redundant subsystem, which could cause the failure of a redundant subsystem and a loss of essential safety function(s). If any tie breakers are closed, the affected redundant electrical power distribution subsystems are considered inoperable. This applies to the onsite, safety related, redundant electrical power distribution subsystems. It does not, however, preclude redundant Class 1E 4.16 kV ESF buses from being powered from the same offsite circuit.

APPLICABILITY

The electrical power distribution subsystems are required to be OPERABLE in MODES 1, 2, and 3 to ensure that:

a. Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of AOOs or abnormal transients; and

b. Adequate core cooling is provided, and containment OPERABILITY and other vital functions are maintained in the event of a postulated DBA.

Electrical power distribution subsystem requirements for MODES 4 and 5 are covered in the Bases for LCO 3.8.10, "Distribution Systems—Shutdown."

ACTIONS

A.1

With one or more required AC buses, load centers, motor control centers, or distribution panels in one division inoperable, the remaining AC electrical power distribution subsystems are capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming no single failure. The overall reliability is reduced, however, because a single failure in the remaining power distribution subsystems could result in the minimum required ESF functions not being supported. Therefore, the required AC

(continued)

INSERT LCO 3.8.7-2

Should one or more buses not listed in LCO 3.8.7 become inoperable due to a failure not affecting the OPERABILITY of a bus listed in LCO 3.8.7 (e.g., a breaker supplying a single MCC faults open), the individual loads on the bus would be considered inoperable, and the appropriate Conditions and Required Actions of the LCOs governing the individual loads would be entered. However, if one or more of these buses become inoperable due to a failure also affecting the OPERABILITY of a bus listed in LCO 3.8.7 (e.g., loss of a 4.16 kV ESF bus), the Conditions and Required Actions of the LCO for the individual loads are not required to be entered, since LCO 3.0.6 allows this exception (i.e., the loads are inoperable due to the inoperability of a support system governed by a Technical Specification; e.g., the 4.16 kV ESF bus).

Table B 3.8.9-1 (page 1 of 1)
AC and DC Electrical Power Distribution System

TYPE	VOLTAGE	[DIVISION 1]*	[DIVISION 2]*
AC safety buses	[4160 V]	[ESF Bus] [NB01]	[ESF Bus] [NB02]
	[480 V]	Load Centers [NG01, NG03]	Load Centers [NG02, NG04]
	[480 V]	Motor Control Centers [NG01A, NG01I, NG01B, NG03C, NG03I, NG03D]	Motor Control Centers [NG02A, NG02I, NG02B, NG04C, NG04I, NG04D]
	[120 V]	Distribution Panels [NP01, NP03]	Distribution Panels [NP02, NP04]
DC buses	[125 V]	Bus [NK01] from battery [NK11] and charger [NK21] Bus [NK03] from battery [NK13] and charger [NK23] Distribution Panels [NK41, NK43, NK51]	Bus [NK02] from battery [NK12] and charger [NK22] Bus [NK04] from battery [NN14] and charger [NK24] Distribution Panels [NK42, NK44, NK52]
AC vital buses	[120 V]	Bus [NN01] from inverter [NN11] connected to bus [NK01] Bus [NN03] from inverter [NN13] connected to bus [NK03]	Bus [NN02] from inverter [NN12] connected to bus [NK02] Bus [NN04] from inverter [NN14] connected to bus [NK04]

* Each [division] of the AC and DC electrical power distribution system is a subsystem.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.10 Distribution Systems—Shutdown

BASES

BACKGROUND

A description of the AC, DC, and AC vital bus electrical power distribution system is provided in the Bases for LCO 3.8.8, "Distribution Systems—Operating."

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident and transient analyses in the FSAR, Chapters 5 and 6 (Ref. 1) and Chapter 15 (Ref. 2), assume Engineered Safety Feature (ESF) systems are OPERABLE. The AC, DC, and AC vital bus electrical power distribution systems are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System, and containment design limits are not exceeded.

The OPERABILITY of the AC, DC, and AC vital bus electrical power distribution system is consistent with the initial assumptions of the accident analyses and the requirements for the supported systems' OPERABILITY.

The OPERABILITY of the minimum AC, DC, and AC vital bus electrical power sources and associated power distribution subsystems during MODES 4 and 5, and during movement of irradiated fuel assemblies in the secondary containment, ensures that:

a. The facility can be maintained in the shutdown or refueling condition for extended periods;

b. Sufficient instrumentation and control capability is available for monitoring and maintaining the unit status; and

c. Adequate power is provided to mitigate events postulated during shutdown, such as an inadvertent draindown of the vessel or a fuel handling accident.

The AC and DC electrical power distribution systems satisfy Criterion 3 of the NRC Policy Statement. (Ref. 3)

(continued)

NUREG 1433 COMPARISON DOCUMENT - JUSTIFICATION FOR DEVIATION

PLANT SPECIFIC DIFFERENCES (continued)

P.35 The additional limits have not been added since Plant Hatch licensing basis does not include these additional values.

P.36 Deleted.

P.37 The Applicability and Condition Statement D have been revised consistent with the actual LCO requirements (as shown in Required Actions D.2.1 and D.2.2 and in the Bases).

P.38 A Note has been added providing allowances similar to those in the current Plant Hatch TS. The current TS note allows the assemblies to be inoperable for 8 hours per month for testing and maintenance. The proposed Note will allow the assemblies to be inoperable a maximum of 6 hours at a time and then only for testing. This allowance is consistent with allowances provided in the other instrumentation TS. Appropriate Bases changes have been made.

P.39 Based on the Plant Hatch instrumentation logic design, the appropriate instrumentation logic, system operation and design description has been provided.

P.40 This table has been deleted since it provides generic and not plant specific types of information. The information in the Table could be misleading as to which plant-specific analyses take credit for these channels to perform a function during accident and transient scenarios.

P.41 These words have been added since all Functions do not have response times.

P.42 This clarification has been added since the RPS is also required to be OPERABLE during conditions that are not MODES.

PLANT SPECIFIC DIFFERENCES (continued)

P.62 This SR can be performed with the reactor at power, thus the words have been modified consistent with other similar SRs.

P.63 The proper basis for the Frequency has been provided.

P.64 This discussion about analytical limits and the derivation of the Allowable Values and trip setpoints has been deleted since it does not apply to this Function.

P.65 This sentence has been deleted to be consistent with NUREG change package BWR-18, Item C.37, which deleted this sentence from the CHANNEL CALIBRATION SR Bases in all applicable instrumentation Bases.

P.66 Deleted.

P.67 The Plant Hatch design for the DG start portion of the subject logic is one-out-of-two, while the rest of the affected components are two-out-of-two. Thus, if the channel is placed in trip as required by Required Action A.1, a DG initiation will occur. Since this is undesirable, the Required Action has been modified to require restoration of the channel, similar to other Required Actions where placing the channel in trip is not desired. Appropriate Bases changes have been made.

P.68 The current Plant Hatch Surveillance Frequencies have been used. The CHANNEL FUNCTIONAL TEST Frequency has been changed from 92 days to the current Plant Hatch requirement of 7 days. Appropriate Bases changes have been made.

PLANT SPECIFIC DIFFERENCES (continued)

P.69 The Function 7.b SR requiring a CHANNEL FUNCTIONAL TEST every 92 days (NUREG SR 3.3.1.1.9) has been deleted. For Plant Hatch, the CHANNEL FUNCTIONAL TEST has been extended to 18 months (see Discussion of change L.10 in ITS: Section 3.3.1.1). The current CHANNEL CALIBRATION is also required every 18 months (NUREG SR 3.3.1.1.13), and the definition of CHANNEL CALIBRATION includes the requirement to perform a CHANNEL FUNCTIONAL TEST. Therefore, repeating this requirement is unnecessary.

P.70 To satisfy Criterion 3 of the NRC Policy Statement, Hatch credits manual actions in the range of 78.8 to 92% of 4.16 kV. Entry into this range is annunciated. The range specified for manual actions indicates that sufficient power is available to the large ECCS motors; however, sufficient voltage for equipment required for LOCA conditions may not be available at lower voltages. The required channels of LOP annunciation instrumentation ensure the initiation of manual actions to protect the ECCS and other assumed systems from degraded voltage without initiating an unnecessary automatic disconnect from the preferred offsite power source. The LOP anticipatory annunciators provide a total time delay of 60 seconds to reduce the possibility of nuisance annunciators, while permitting prompt detection of potential low voltage conditions. Since Hatch takes credit for the annunciators, they have been added to Table 3.3.8.1-1. New LCO CONDITION B, addressing the annunciation Function, has been added, and the other CONDITIONS have been renumbered and amended as necessary to account for the annunciation. Appropriate SRs are defined for the annunciator bus undervoltage relays and the associated time delays.

GENERIC APPROVED/PENDING CHANGES TO NUREG 1433

GP.1 Changed to be consistent with NUREG change package BWR-18, Items C.2, C.18, C.19, C.20, C.21, C.22, C.23, C.24, C.25, C.28, C.29, C.30, C.32, C.33, C.34, C.35, C.36, C.37, C.38, C.39, C.40, C.41, C.42, C.43, C.44, and C.45.

GA.2 Change approved per package BWR-01A, Item C.1, 3/20/93.

GP.3 Changed to be consistent with NUREG change package BWR-19, Items C.1, C.2, C.4, C.7, C.8, and C.9.

GA.4 Change approved per package BWR-06 Item C.9, Revs. 2 and 3, 10/13/93.

GA.5 Change approved per package NRC-02, Items C.15 and C.21, 5/20/93.

GP.6 Changed to be consistent with NUREG package BWOG-09, Item C.26.

PLANT SPECIFIC DIFFERENCES (continued)

P.37 The Frequency of this SR has been changed to 184 days. This SR is not currently required by Plant Hatch TS, but is being performed per procedures every 184 days. This Frequency has been shown to be adequate. In addition, the storage tanks are above the ground water level, thus water should not "seep" into the tanks. The Bases Surveillance Frequency discussion has been modified to reflect the reason for the Frequency.

P.38 The NUREG wording has been changed to incorporate the Plant Hatch design voltage requirements and reasons for these requirements.

P.39 Changes were made for clarity and to utilize plant specific terminology, as well as to describe the manner in which Plant Hatch performs the tests (for SR 3.6.4.8 Bases change). In addition, the cell parameter limits are not necessarily chosen conservatively, thus this word has been deleted from the LCO section of the Bases for LCO 3.8.6).

P.40 The bus list in LCO 3.8.7 is the current Hatch licensing basis for required electrical distribution subsystems in MODES 1, 2, and 3. Other buses, such as motor control centers (MCC) and distribution panels, which help comprise the AC and DC Distribution Systems were not listed in LCO 3.8.7, since the loss of electrical loads associated with these buses may not result in a complete loss of a redundant safety function necessary to shut down the reactor and maintain it in a safe condition. Therefore, should one or more of these buses become inoperable due to a failure not affecting the OPERABILITY of a bus listed in LCO 3.8.7 (e.g., a breaker supplying a single MCC faults open), the individual loads on the bus would be considered inoperable, and the appropriate Conditions and Required Actions of the LCOs governing the individual loads would be entered. If however, one or more of these buses is inoperable due to a failure also affecting the OPERABILITY of a bus listed in LCO 3.8.7 (e.g., loss of a 4.16 kV ESF bus, which results in de-energization of all buses powered from the 4.16 kV ESF bus), the Conditions and Required Actions of the LCO for the individual loads are not required to be entered, since LCO 3.0.6 allows this exception (i.e., the loads are inoperable due to the inoperability of a support system governed by a Technical Specification; the 4.16 kV ESF bus).

PLANT SPECIFIC DIFFERENCES

P.41
(continued)

the Markup of the Current Technical Specifications Section 3.8.4 M.1 (Unit 1) and M.3 (Unit 2), these surveillances are additional requirements, even without specific resistance values.

Based on the above discussion, we believe the Hatch ITS proposed specification is appropriate. In summary, the NUREG values specified tend to be manufactures' values, not OPERABILITY values. The configuration of the batteries will lead to several different values, not just three. Hatch CTS do not include these requirements, and we currently have procedures for performing battery inspections.

P.42 The substitution of a modified performance discharge test for a service test may be helpful to gather additional data points for trending capacity as a battery nears its end of life, but before more frequent testing would normally be required. For this reason, this substitution should be allowed, though not required. Since the modified performance discharge test envelopes the duty cycle of the service test, thus making it a harsher test on the battery, it may be substituted for the service test at any time. (This is stated in the draft revision of IEEE-450.) Also, to simplify procedures, the use of a modified performance test may be substituted for the service test throughout the life of the battery. Design configuration controls should verify the continued enveloping of the service test duty cycle by that of the modified performance discharge test.

P.43 The diesel generator accelerated test frequency requirements are relocated in their current licensing bases form to plant procedures. A plant procedure implements the current Technical Specifications requirements, as well as the requirements and responsibilities for tracking emergency DG failures for the determination and reporting of reaching trigger values specified in NUMARC 87-00. These requirements are more restrictive than those specified in NUREG 1433.

PLANT SPECIFIC DIFFERENCES (continued)

P.24 The provisions of SR 3.0.2 and SR 3.0.3 would have been applicable to the diesel fuel oil testing provisions if they had been left in the LCOs of Section 3.8. Since these Section 3.0 provisions are not generally applicable to Administrative Controls, then the applicability must be specifically stated in Section 5.0 provisions.

P.25 The description of the entry conditions into the SFDP are clarified and generalized to assure that they include all possible required entry conditions.

P.26 A clarification is added to include in the annual occupational radiation exposure report, only those other personnel for whom monitoring was required. This change does not modify the present intent of the NUREG.

P.27 A clarification is added to the monthly operating report requirement to state that the safety/relief valves are those for "main steam." This change does not modify the present intent of the NUREG.

P.28 The NUREG provides examples of safety analysis limits that are met as a result of ensuring that core operating limits are properly determined. The proposed change will replace these examples by stating that specified acceptable fuel design limits will be met. This change meets the intent of the present NUREG and ensures that all applicable limits are met.

P.29 Reference to LCO 3.3.3.1 for Post Accident Monitoring Instrumentation is all that is necessary to locate this special reporting requirement.

P.30 Changes to be consistent with plant specific terminology.

P.31 Changes to clarify the control room command function and shift crew composition for a dual unit plant with a common control room.

P.32 A direct reference to 10 CFR 50.54 for determination of minimum shift crew composition is added. Without this reference, ITS 5.2.2.b could be incorrectly construed to define these requirements.

PLANT SPECIFIC DIFFERENCES (continued)

P.33 The diesel generator accelerated test frequency requirements are relocated in their current licensing bases form to plant procedures. A plant procedure implements the current Technical Specifications requirements, as well as the requirements and responsibilities for tracking emergency DG failures for the determination and reporting of reaching trigger values specified in NUMARC 87-00. These requirements are more restrictive than those specified in NUREG 1433.

GENERIC APPROVED/PENDING CHANGES TO NUREG 1433

GP.1 Changed to be consistent with NUREG change package BWOG-09, Items C.1 through C.17 and C.19 through C.25.

GA.2 Change approved per package WOG-06, Items C.1, C.5, and C.7, 3/20/93.

GA.3 Change approved per package BWR-06, Item C.7, 5/20/93.

GA.4 Change approved per package NRC-02, Item C.22, 5/20/93.